

FEDERAL OPERATING PERMIT

A FEDERAL OPERATING PERMIT IS HEREBY ISSUED TO
Lower Colorado River Authority

AUTHORIZING THE OPERATION OF
Thomas C. Ferguson Power Plant
Electric Services

LOCATED AT
Llano County, Texas
Latitude 30° 33' 27" Longitude 98° 22' 23"
Regulated Entity Number: RN100219468

This permit is issued in accordance with and subject to the Texas Clean Air Act (TCAA), Chapter 382 of the Texas Health and Safety Code and Title 30 Texas Administrative Code Chapter 122 (30 TAC Chapter 122), Federal Operating Permits. Under 30 TAC Chapter 122, this permit constitutes the permit holder's authority to operate the site, emission units and affected source listed in this permit. Operations of the site, emission units and affected source listed in this permit are subject to all additional rules or amended rules and orders of the Commission pursuant to the TCAA.

This permit does not relieve the permit holder from the responsibility of obtaining New Source Review authorization for new, modified, or existing facilities in accordance with 30 TAC Chapter 116, Control of Air Pollution by Permits for New Construction or Modification.

The site, emission units and affected source authorized by this permit shall be operated in accordance with 30 TAC Chapter 122, the general terms and conditions, special terms and conditions, and attachments contained herein.

This permit shall expire five years from the date of issuance. The renewal requirements specified in 30 TAC § 122.241 must be satisfied in order to renew the authorization to operate the site, emission units and affected source.

Permit No: O19 Issuance Date: August 18, 2015

For the Commission

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General Terms and Conditions

The permit holder shall comply with all terms and conditions contained in 30 TAC § 122.143 (General Terms and Conditions), 30 TAC § 122.144 (Recordkeeping Terms and Conditions), 30 TAC § 122.145 (Reporting Terms and Conditions), and 30 TAC § 122.146 (Compliance Certification Terms and Conditions).

In accordance with 30 TAC § 122.144(1), records of required monitoring data and support information required by this permit, or any applicable requirement codified in this permit, are required to be maintained for a period of five years from the date of the monitoring report, sample, or application unless a longer data retention period is specified in an applicable requirement. The five year record retention period supersedes any less stringent retention requirement that may be specified in a condition of a permit identified in the New Source Review Authorization attachment.

If the permit holder chooses to demonstrate that this permit is no longer required, a written request to void this permit shall be submitted to the Texas Commission on Environmental Quality (TCEQ) by the Responsible Official in accordance with 30 TAC § 122.161(e). The permit holder shall comply with the permit's requirements, including compliance certification and deviation reporting, until notified by the TCEQ that this permit is voided.

The permit holder shall comply with 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit.

All reports required by this permit must include in the submittal a cover letter which identifies the following information: company name, TCEQ regulated entity number, air account number (if assigned), site name, area name (if applicable), and Air Permits Division permit number(s).

Special Terms and Conditions:

Emission Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting

1. Permit holder shall comply with the following requirements:
 - A. Emission units (including groups and processes) in the Applicable Requirements Summary attachment shall meet the limitations, standards, equipment specifications, monitoring, recordkeeping, reporting, testing, and other requirements listed in the Applicable Requirements Summary attachment to assure compliance with the permit.
 - B. The textual description in the column titled "Textual Description" in the Applicable Requirements Summary attachment is not enforceable and is not deemed as a substitute for the actual regulatory language. The Textual Description is provided for information purposes only.
 - C. A citation listed on the Applicable Requirements Summary attachment, which has a notation [G] listed before it, shall include the referenced section and subsection for all commission rules, or paragraphs for all federal and state regulations and all subordinate paragraphs, subparagraphs and clauses, subclauses, and items contained within the referenced citation as applicable requirements.

- D. When a grouped citation, notated with a [G] in the Applicable Requirements Summary, contains multiple compliance options, the permit holder must keep records of when each compliance option was used.
 - E. Emission units subject to 40 CFR Part 63, Subpart ZZZZ as identified in the attached Applicable Requirements Summary table are subject to 30 TAC Chapter 113, Subchapter C, § 113.1090 which incorporates the 40 CFR Part 63 Subpart by reference.
2. The permit holder shall comply with the following sections of 30 TAC Chapter 101 (General Air Quality Rules):
- A. Title 30 TAC § 101.1 (relating to Definitions), insofar as the terms defined in this section are used to define the terms used in other applicable requirements
 - B. Title 30 TAC § 101.3 (relating to Circumvention)
 - C. Title 30 TAC § 101.8 (relating to Sampling), if such action has been requested by the TCEQ
 - D. Title 30 TAC § 101.9 (relating to Sampling Ports), if such action has been requested by the TCEQ
 - E. Title 30 TAC § 101.10 (relating to Emissions Inventory Requirements)
 - F. Title 30 TAC § 101.201 (relating to Emission Event Reporting and Recordkeeping Requirements)
 - G. Title 30 TAC § 101.211 (relating to Scheduled Maintenance, Start-up, and Shutdown Reporting and Recordkeeping Requirements)
 - H. Title 30 TAC § 101.221 (relating to Operational Requirements)
 - I. Title 30 TAC § 101.222 (relating to Demonstrations)
 - J. Title 30 TAC § 101.223 (relating to Actions to Reduce Excessive Emissions)
3. Permit holder shall comply with the following requirements of 30 TAC Chapter 111:
- A. Visible emissions from stationary vents with a flow rate of less than 100,000 actual cubic feet per minute and constructed after January 31, 1972 that are not listed in the Applicable Requirements Summary attachment for 30 TAC Chapter 111, Subchapter A, Division 1, shall not exceed 20% opacity averaged over a six-minute period. The permit holder shall comply with the following requirements for stationary vents at the site subject to this standard:
 - (i) Title 30 TAC § 111.111(a)(1)(B) (relating to Requirements for Specified Sources)
 - (ii) Title 30 TAC § 111.111(a)(1)(E)
 - (iii) Title 30 TAC § 111.111(a)(1)(F)(i), (ii), (iii), or (iv)

- (iv) For emission units with vent emissions subject to 30 TAC § 111.111(a)(1)(B), complying with 30 TAC § 111.111(a)(1)(F)(ii), (iii), or (iv), and capable of producing visible emissions from, but not limited to, particulate matter, acid gases and NO_x, the permit holder shall also comply with the following periodic monitoring requirements for the purpose of annual compliance certification under 30 TAC § 122.146. These periodic monitoring requirements do not apply to vents that are not capable of producing visible emissions such as vents that emit only colorless VOCs; vents from non-fuming liquids; vents that provide passive ventilation, such as plumbing vents; or vent emissions from any other source that does not obstruct the transmission of light. Vents, as specified in the “Applicable Requirements Summary” attachment, that are subject to the emission limitation of 30 TAC § 111.111(a)(1)(B) are not subject to the following periodic monitoring requirements:
- (1) An observation of stationary vents from emission units in operation shall be conducted at least once during each calendar quarter unless the emission unit is not operating for the entire quarter.
 - (2) For stationary vents from a combustion source, if an alternative to the normally fired fuel is fired for a period greater than or equal to 24 consecutive hours, the permit holder shall conduct an observation of the stationary vent for each such period to determine if visible emissions are present. If such period is greater than 3 months, observations shall be conducted once during each quarter. Supplementing the normally fired fuel with natural gas or fuel gas to increase the net heating value to the minimum required value does not constitute creation of an alternative fuel.
 - (3) Records of all observations shall be maintained.
 - (4) Visible emissions observations of emission units operated during daylight hours shall be conducted no earlier than one hour after sunrise and no later than one hour before sunset. Visible emissions observations of emission units operated only at night must be made with additional lighting and the temporary installation of contrasting backgrounds. Visible emissions observations shall be made during times when the activities described in 30 TAC § 111.111(a)(1)(E) are not taking place. Visible emissions shall be determined with each stationary vent in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 mile, away from each stationary vent during the observation. For outdoor locations, the observer shall select a position where the sun is not directly in the observer’s eyes. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. A certified opacity reader is not required for visible emissions observations.

(5) Compliance Certification:

- (a) If visible emissions are not present during the observation, the RO may certify that the source is in compliance with the applicable opacity requirement in 30 TAC § 111.111(a)(1) and (a)(1)(B).
- (b) However, if visible emissions are present during the observation, the permit holder shall either list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2) or conduct the appropriate opacity test specified in 30 TAC § 111.111(a)(1)(F) as soon as practicable, but no later than 24 hours after observing visible emissions to determine if the source is in compliance with the opacity requirements. If an opacity test is performed and the source is determined to be in compliance, the RO may certify that the source is in compliance with the applicable opacity requirement. However, if an opacity test is performed and the source is determined to be out of compliance, the permit holder shall list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2). The opacity test must be performed by a certified opacity reader.
- (c) Some vents may be subject to multiple visible emission or monitoring requirements. All credible data must be considered when certifying compliance with this requirement even if the observation or monitoring was performed to demonstrate compliance with a different requirement.

B. For visible emissions from a building, enclosed facility, or other structure; the permit holder shall comply with the following requirements:

- (i) Title 30 TAC § 111.111(a)(7)(A) (relating to Requirements for Specified Sources)
- (ii) Title 30 TAC § 111.111(a)(7)(B)(i) or (ii)
- (iii) For a building containing an air emission source, enclosed facility, or other structure containing or associated with an air emission source subject to 30 TAC § 111.111(a)(7)(A), complying with 30 TAC § 111.111(a)(7)(B)(i) or (ii), and capable of producing visible emissions from, but not limited to, particulate matter, acid gases and NO_x, the permit holder shall also comply with the following periodic monitoring requirements for the purpose of annual compliance certification under 30 TAC § 122.146:
 - (1) An observation of visible emissions from a building containing an air emission source, enclosed facility, or other structure containing or associated with an air emission source which is required to comply with 30 TAC § 111.111(a)(7)(A) shall be conducted at least once during each calendar quarter unless the

air emission source or enclosed facility is not operating for the entire quarter.

- (2) Records of all observations shall be maintained.
- (3) Visible emissions observations of air emission sources or enclosed facilities operated during daylight hours shall be conducted no earlier than one hour after sunrise and no later than one hour before sunset. Visible emissions observations of air emission sources or enclosed facilities operated only at night must be made with additional lighting and the temporary installation of contrasting backgrounds. Visible emissions shall be determined with each emissions outlet in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 mile, away from each emissions outlet during the observation. For outdoor locations, the observer shall select a position where the sun is not directly in the observer's eyes. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. A certified opacity reader is not required for visible emissions observations.
- (4) Compliance Certification:
 - (a) If visible emissions are not present during the observation, the RO may certify that the source is in compliance with the applicable opacity requirement in 30 TAC § 111.111(a)(7) and (a)(7)(A)
 - (b) However, if visible emissions are present during the observation, the permit holder shall either list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2) or conduct the appropriate opacity test specified in 30 TAC § 111.111(a)(7)(B) as soon as practicable, but no later than 24 hours after observing visible emissions to determine if the source is in compliance with the opacity requirements. If an opacity test is performed and the source is determined to be in compliance, the RO may certify that the source is in compliance with the applicable opacity requirement. However, if an opacity test is performed and the source is determined to be out of compliance, the permit holder shall list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2). The opacity test must be performed by a certified opacity reader

- C. For visible emissions from all other sources not specified in 30 TAC § 111.111(a)(1), (4), or (7); the permit holder shall comply with the following requirements:

- (i) Title 30 TAC § 111.111(a)(8)(A) (relating to Requirements for Specified Sources)
- (ii) Title 30 TAC § 111.111(a)(8)(B)(i) or (ii)
- (iii) For a source subject to 30 TAC § 111.111(a)(8)(A), complying with 30 TAC § 111.111(a)(8)(B)(i) or (ii), and capable of producing visible emissions from, but not limited to, particulate matter, acid gases and NO_x, the permit holder shall also comply with the following periodic monitoring requirements for the purpose of annual compliance certification under 30 TAC § 122.146:
 - (1) An observation of visible emissions from a source which is required to comply with 30 TAC § 111.111(a)(8)(A) shall be conducted at least once during each calendar quarter unless the source is not operating for the entire quarter.
 - (2) Records of all observations shall be maintained.
 - (3) Visible emissions observations of sources operated during daylight hours shall be conducted no earlier than one hour after sunrise and no later than one hour before sunset. Visible emissions observations of sources operated only at night must be made with additional lighting and the temporary installation of contrasting backgrounds. Visible emissions shall be determined with each source in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 mile, away from each source during the observation. For outdoor locations, the observer shall select a position where the sun is not directly in the observer's eyes. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. A certified opacity reader is not required for visible emissions observations.
 - (4) Compliance Certification:
 - (a) If visible emissions are not present during the observation, the RO may certify that the source is in compliance with the applicable opacity requirement in 30 TAC § 111.111(a)(8) and (a)(8)(A)
 - (b) However, if visible emissions are present during the observation, the permit holder shall either list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2) or conduct the appropriate opacity test specified in 30 TAC § 111.111(a)(8)(B) as soon as practicable, but no later than 24 hours after observing visible emissions to determine if the source is in compliance with the opacity requirements. If an opacity test is performed and the

source is determined to be in compliance, the RO may certify that the source is in compliance with the applicable opacity requirement. However, if an opacity test is performed and the source is determined to be out of compliance, the permit holder shall list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2). The opacity test must be performed by a certified opacity reader.

- D. Certification of opacity readers determining opacities under Method 9 (as outlined in 40 CFR Part 60, Appendix A) to comply with opacity monitoring requirements shall be accomplished by completing the Visible Emissions Evaluators Course, or approved agency equivalent, no more than 180 days before the opacity reading.
 - E. For emission units with contributions from uncombined water, the permit holder shall comply with the requirements of 30 TAC § 111.111(b).
 - F. Emission limits on nonagricultural processes, except for the steam generators specified in 30 TAC § 111.153, shall comply with the following requirements:
 - (i) Emissions of PM from any source may not exceed the allowable rates as required in 30 TAC § 111.151(a) (relating to Allowable Emissions Limits)
 - (ii) Sources with an effective stack height (h_e) less than the standard effective stack height (H_e), must reduce the allowable emission level by multiplying it by $[h_e/H_e]^2$ as required in 30 TAC § 111.151(b)
 - (iii) Effective stack height shall be calculated by the equation specified in 30 TAC § 111.151(c)
 - G. Outdoor burning, as stated in 30 TAC § 111.201, shall not be authorized unless the following requirements are satisfied:
 - (i) Title 30 TAC § 111.205 (relating to Exception for Fire Training)
 - (ii) Title 30 TAC § 111.207 (relating to Exception for Recreation, Ceremony, Cooking, and Warmth)
 - (iii) Title 30 TAC § 111.219 (relating to General Requirements for Allowable Outdoor Burning)
 - (iv) Title 30 TAC § 111.221 (relating to Responsibility for Consequences of Outdoor Burning)
4. The permit holder shall comply with the following requirements for units subject to any subpart of 40 CFR Part 60, unless otherwise stated in the applicable subpart:
- A. Title 40 CFR § 60.7 (relating to Notification and Recordkeeping)
 - B. Title 40 CFR § 60.8 (relating to Performance Tests)
 - C. Title 40 CFR § 60.11 (relating to Compliance with Standards and Maintenance Requirements)

- D. Title 40 CFR § 60.12 (relating to Circumvention)
 - E. Title 40 CFR § 60.13 (relating to Monitoring Requirements)
 - F. Title 40 CFR § 60.14 (relating to Modification)
 - G. Title 40 CFR § 60.15 (relating to Reconstruction)
 - H. Title 40 CFR § 60.19 (relating to General Notification and Reporting Requirements)
5. The permit holder shall comply with the requirements of 30 TAC Chapter 113, Subchapter C, § 113.100 for units subject to any subpart of 40 CFR Part 63, unless otherwise stated in the applicable subpart.

Additional Monitoring Requirements

6. The permit holder shall comply with the periodic monitoring requirements as specified in the attached "Periodic Monitoring Summary" upon issuance of the permit. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permit holder shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time specified in the "Periodic Monitoring Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances to avoid reporting deviations. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

New Source Review Authorization Requirements

7. Permit holder shall comply with the requirements of New Source Review authorizations issued or claimed by the permit holder for the permitted area, including permits, permits by rule, standard permits, flexible permits, special permits, permits for existing facilities including Voluntary Emissions Reduction Permits and Electric Generating Facility Permits issued under 30 TAC Chapter 116, Subchapter I, or special exemptions referenced in the New Source Review Authorization References attachment. These requirements:
- A. Are incorporated by reference into this permit as applicable requirements
 - B. Shall be located with this operating permit
 - C. Are not eligible for a permit shield
8. The permit holder shall comply with the general requirements of 30 TAC Chapter 106, Subchapter A or the general requirements, if any, in effect at the time of the claim of any PBR.
9. The permit holder shall maintain records to demonstrate compliance with any emission limitation or standard that is specified in a permit by rule (PBR) or Standard Permit listed in the New Source Review Authorizations attachment. The records shall yield

reliable data from the relevant time periods that are representative of the emission unit's compliance with the PBR or Standard Permit. These records may include, but are not limited to, production capacity and throughput, hours of operation, safety data sheets (SDS), chemical composition of raw materials, speciation of air contaminant data, engineering calculations, maintenance records, fugitive data, performance tests, capture/control device efficiencies, direct pollutant monitoring (CEMS, COMS, or PEMS), or control device parametric monitoring. These records shall be made readily accessible and available as required by 30 TAC § 122.144. Any monitoring or recordkeeping data indicating noncompliance with the PBR or Standard Permit shall be considered and reported as a deviation according to 30 TAC § 122.145 (Reporting Terms and Conditions).

Compliance Requirements

10. The permit holder shall certify compliance in accordance with 30 TAC § 122.146. The permit holder shall comply with 30 TAC § 122.146 using at a minimum, but not limited to, the continuous or intermittent compliance method data from monitoring, recordkeeping, reporting, or testing required by the permit and any other credible evidence or information. The certification period may not exceed 12 months and the certification must be submitted within 30 days after the end of the period being certified.
11. Use of Discrete Emission Credits to comply with the applicable requirements:
 - A. Unless otherwise prohibited, the permit holder may use discrete emission credits to comply with the following applicable requirements listed elsewhere in this permit:
 - (i) Title 30 TAC Chapter 115
 - (ii) Title 30 TAC Chapter 117
 - (iii) If applicable, offsets for Title 30 TAC Chapter 116
 - (iv) Temporarily exceed state NSR permit allowables
 - B. The permit holder shall comply with the following requirements in order to use the credit to comply with the applicable requirements:
 - (i) The permit holder must notify the TCEQ according to 30 TAC § 101.376(d)
 - (ii) The discrete emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 4
 - (iii) The executive director has approved the use of the discrete emission credits according to 30 TAC § 101.376(d)(1)(A)
 - (iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.372(h) and 30 TAC Chapter 122

- (v) Title 30 TAC § 101.375 (relating to Emission Reductions Achieved Outside the United States)

Protection of Stratospheric Ozone

- 12. Permit holders at a site subject to Title VI of the FCAA Amendments shall meet the following requirements for protection of stratospheric ozone:
 - A. Any on site servicing, maintenance, and repair on refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants or non-exempt substitutes shall be conducted in accordance with 40 CFR Part 82, Subpart F. Permit holders shall ensure that repairs on or refrigerant removal from refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants are performed only by properly certified technicians using certified equipment. Records shall be maintained as required by 40 CFR Part 82, Subpart F.
 - B. The permit holder shall comply with 40 CFR Part 82, Subpart F related to the disposal requirements for appliances using Class I or Class II (ozone-depleting) substances or non-exempt substitutes as specified in 40 CFR §§ 82.150 - 82.166 and the applicable Part 82 Appendices.

Permit Location

- 13. The permit holder shall maintain a copy of this permit and records related to requirements listed in this permit on site.

Permit Shield (30 TAC § 122.148)

- 14. A permit shield is granted for the emission units, groups, or processes specified in the attached "Permit Shield." Compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements listed in the attachment "Permit Shield." Permit shield provisions shall not be modified by the executive director until notification is provided to the permit holder. No later than 90 days after notification of a change in a determination made by the executive director, the permit holder shall apply for the appropriate permit revision to reflect the new determination. Provisional terms are not eligible for this permit shield. Any term or condition, under a permit shield, shall not be protected by the permit shield if it is replaced by a provisional term or condition or the basis of the term and condition changes.

Acid Rain Permit Requirements

- 15. For units CT-1 and CT-2 (identified in the Certificate of Representation as units CT-1 and CT-2), located at the affected source identified by ORIS/Facility code 4937, the designated representative and the owner or operator, as applicable, shall comply with the following Acid Rain Permit requirements.
 - A. General Requirements
 - (i) Under 30 TAC § 122.12(1) and 40 CFR Part 72, the Acid Rain Permit requirements contained here are a separable portion of the Federal Operating Permit (FOP) and have an independent public comment process which may be separate from, or combined with the FOP.

- (ii) The owner and operator shall comply with the requirements of 40 CFR Part 72 and 40 CFR Part 76. Any noncompliance with the Acid Rain Permit will be considered noncompliance with the FOP and may be subject to enforcement action.
- (iii) The owners and operators of the affected source shall operate the source and the unit in compliance with the requirements of this Acid Rain Permit and all other applicable State and federal requirements.
- (iv) The owners and operators of the affected source shall comply with the General Terms and Conditions of the FOP that incorporates this Acid Rain Permit.
- (v) The term for the Acid Rain permit shall commence with the issuance of the FOP that incorporates the Acid Rain permit and shall be run concurrent with the remainder of the term of the FOP. Renewal of the Acid Rain permit shall coincide with the renewal of the FOP that incorporates the Acid Rain permit and subsequent terms shall be no more than five years from the date of renewal of the FOP and run concurrent with the permit term of the FOP.

B. Monitoring Requirements

- (i) The owners and operators, and the designated representative, of the affected source and each affected unit at the source shall comply with the monitoring requirements contained 40 CFR Part 75.
- (ii) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 and any other credible evidence shall be used to determine compliance by the affected source with the acid rain emissions limitations and emissions reduction requirements for SO₂ and NO_x under the ARP.
- (iii) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emission of other pollutants or other emissions characteristics at the unit under other applicable requirements of the FCAA Amendments (42 U.S.C. 7401, as amended November 15, 1990) and other terms and conditions of the operating permit for the source.

C. SO₂ emissions requirements

- (i) The owners and operators of each source and each affected unit at the source shall comply with the applicable acid rain emissions limitations for SO₂.
- (ii) As of the allowance transfer deadline the owners and operators of the affected source and each affected unit at the source shall hold, in the unit's compliance subaccount, allowances in an amount not less than the total annual emissions of SO₂ for the previous calendar year.
- (iii) Each ton of SO₂ emitted in excess of the acid rain emissions limitations for SO₂ shall constitute a separate violation of the FCAA amendments.

- (iv) An affected unit shall be subject to the requirements under (i) and (ii) of the SO₂ emissions requirements as follows:
 - (1) Starting January 1, 2000, an affected unit under 40 CFR § 72.6(a)(2); or
 - (2) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR § 72.6(a)(3).
- (v) Allowances shall be held in, deducted from, or transferred into or among Allowance Tracking System accounts in accordance with the requirements of the ARP.
- (vi) An allowance shall not be deducted, for compliance with the requirements of this permit, in a calendar year before the year for which the allowance was allocated.
- (vii) An allowance allocated by the EPA Administrator or under the ARP is a limited authorization to emit SO₂ in accordance with the ARP. No provision of the ARP, Acid Rain permit application, this Acid Rain Permit, or an exemption under 40 CFR §§ 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (viii) An allowance allocated by the EPA Administrator under the ARP does not constitute a property right.

D. NO_x Emission Requirements

- (i) The owners and operators of the source and each affected unit at the source shall comply with the applicable acid rain emissions limitations for NO_x under 40 CFR Part 76.

E. Excess emissions requirements for SO₂ and NO_x.

- (i) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
- (ii) If an affected source has excess emissions in any calendar year shall, as required by 40 CFR Part 77:
 - (1) Pay, without demand, the penalty required and pay, upon demand, the interest on that penalty.
 - (2) Comply with the terms of an approved offset plan.

F. Recordkeeping and Reporting Requirements

- (i) Unless otherwise provided, the owners and operators of the affected source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at

any time before the end of 5 years, in writing by the permitting authority or the EPA Administrator.

- (1) The certificate of representation for the designated representative for the source and each affected unit and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR § 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.
 - (2) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping (rather than a five-year period cited in 30 TAC § 122.144), the 3-year period shall apply.
 - (3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the ARP or relied upon for compliance certification.
 - (4) Copies of all documents used to complete an acid rain permit application and any other submission under the ARP or to demonstrate compliance with the requirements of the ARP.
- (ii) The designated representative of an affected source and each affected unit at the source shall submit the reports required under the ARP including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

G. Liability

- (i) Any person who knowingly violates any requirement or prohibition of the ARP, a complete acid rain permit application, an acid rain permit, or a written exemption under 40 CFR §§ 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to FCAA § 113(c).
- (ii) Any person who knowingly makes a false, material statement in any record, submission, or report under the ARP shall be subject to criminal enforcement pursuant to FCAA § 113(c) and 18 U.S.C. 1001.
- (iii) No permit revision shall excuse any violation of the requirements of the ARP that occurs prior to the date that the revision takes effect.
- (iv) The affected source and each affected unit shall meet the requirements of the ARP contained in 40 CFR Parts 72 through 78.
- (v) Any provision of the ARP that applies to an affected source or the designated representative of an affected source shall also apply to the owners and operators of such source and of the affected units at the source.
- (vi) Any provision of the ARP that applies to an affected unit (including a provision applicable to the DR of an affected unit) shall also apply to the

owners and operators of such unit. Except as provided under 40 CFR § 72.44 (Phase II repowering extension plans) and 40 CFR § 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR §§ 75.16, 75.17, and 75.18), the owners and operators and the DR of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the DR and that is located at a source of which they are not owners or operators or the DR.

- (vii) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or DR of such source or unit, shall be a separate violation of the FCAA Amendments.
- H. Effect on other authorities. No provision of the ARP, an acid rain permit application, an acid rain permit, or an exemption under 40 CFR §§ 72.7 or 72.8 shall be construed as:
- (i) Except as expressly provided in Title IV of the FCAA Amendments, exempting or excluding the owners and operators and, to the extent applicable, the DR of an affected source or affected unit from compliance with any other provision of the FCAA Amendments, including the provisions of Title I of the FCAA Amendments relating to applicable National Ambient Air Quality Standards or State Implementation Plans.
 - (ii) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the FCAA Amendments.
 - (iii) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law.
 - (iv) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
 - (v) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.
- I. The number of SO₂ allowances allocated by the EPA in 40 CFR Part 73 is enforceable only by the EPA Administrator.

Acid Rain Unit Exemptions

16. As reference only information, the following unit (BOILER 1) has received an acid rain unit exemption and is not incorporated into the Acid Rain Permit.

Clean Air Interstate Rule Permit Requirements

17. For units CT-1 and CT-2 (identified in the Certificate of Representation as units CT-1 and CT-2), located at the site identified by ORIS/Facility code 4937, the designated

representative and the owner or operator, as applicable, shall comply with the following Clean Air Interstate Rule (CAIR) Permit requirements. Until approval of the Texas CAIR SIP by EPA, the permit holder shall comply with the equivalent requirements of 40 CFR Part 97 in place of the referenced 40 CFR Part 96 requirements in the Texas CAIR permit and 30 TAC Chapter 122 requirements.

A. General Requirements

- (i) Under 30 TAC § 122.420(b) and 40 CFR §§ 96.120(b) and 96.220(b) the CAIR Permit requirements contained here are a separable portion of the Federal Operating Permit (FOP).
- (ii) The owners and operators of the CAIR NO_x and the CAIR SO₂ source shall operate the source and the unit in compliance with the requirements of this CAIR permit and all other applicable State and federal requirements.
- (iii) The owners and operators of the CAIR NO_x and the CAIR SO₂ source shall comply with the General Terms and Conditions of the FOP that incorporates this CAIR Permit.
- (iv) The term for the initial CAIR permit shall commence with the issuance of the revision containing the CAIR permit and shall be the remaining term for the FOP that incorporates the CAIR permit. Renewal of the initial CAIR permit shall coincide with the renewal of the FOP that incorporates the CAIR permit and subsequent terms shall be no more than five years from the date of renewal of the FOP and run concurrent with the permit term of the FOP.

B. Monitoring and Reporting Requirements

- (i) The owners and operators, and the CAIR designated representative, of the CAIR NO_x source and each CAIR NO_x unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements contained 40 CFR Part 96, Subpart HH.
- (ii) The owners and operators, and the CAIR designated representative, of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements contained 40 CFR Part 96, Subpart HHH.
- (iii) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HH and any other credible evidence shall be used to determine compliance by the CAIR NO_x source with the CAIR NO_x emissions limitation.
- (iv) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHH and any other credible evidence shall be used to determine compliance by the CAIR SO₂ source with the CAIR SO₂ emissions limitation.

C. NO_x emissions requirements

- (i) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the

source shall hold, in the source's compliance account, CAIR NO_x allowances available for compliance deductions for the control period under 40 CFR § 96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x units at the source, as determined in accordance with the requirements of 40 CFR Part 96, Subpart HH.

- (ii) A CAIR NO_x unit shall be subject to the requirements of paragraph C.(i) of this CAIR Permit starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under 40 CFR § 96.170(b)(1), (2), or (5).
- (iii) A CAIR NO_x allowance shall not be deducted, for compliance with the requirements of this permit, for a control period in a calendar year before the year for which the CAIR NO_x allowance was allocated.
- (iv) CAIR NO_x allowances shall be held in, deducted from or transferred into or among CAIR NO_x Allowance Tracking System accounts in accordance with the requirements of 40 CFR Part 96, Subpart FF or Subpart GG.
- (v) A CAIR NO_x allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_x Annual Trading Program. No provision of the CAIR NO_x Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under 40 CFR § 96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
- (vi) A CAIR NO_x allowance does not constitute a property right.
- (vii) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FF or Subpart GG, every allocation, transfer, or deduction of a CAIR NO_x allowance to or from a CAIR NO_x unit's compliance account is incorporated automatically in this CAIR permit.

D. NO_x excess emissions requirement

- (i) If a CAIR NO_x source emits nitrogen oxides during any control period in excess of the CAIR NO_x emissions limitation, the owners and operators of the source and each CAIR NO_x unit at the source shall surrender the CAIR NO_x allowances required for deduction under 40 CFR § 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law.
- (ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AA, the Clean Air Act, and applicable State law.

E. SO₂ emissions requirements

- (i) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall hold, in the source's compliance account, CAIR SO₂

allowances available for compliance deductions for the control period under 40 CFR § 96.254(a) and (b) in an amount not less than the tons of total sulfur dioxides emissions for the control period from all CAIR SO₂ units at the source, as determined in accordance with the requirements of 40 CFR Part 96, Subpart HHH.

- (ii) A CAIR SO₂ unit shall be subject to the requirements of paragraph E.(i) of this CAIR Permit starting on the later of January 1, 2010, or the deadline for meeting the unit's monitor certification requirements under 40 CFR § 96.270(b)(1), (2), or (5).
- (iii) A CAIR SO₂ allowance shall not be deducted, for compliance with the requirements of this permit, for a control period in a calendar year before the year for which the CAIR SO₂ allowance was allocated.
- (iv) CAIR SO₂ allowances shall be held in, deducted from, or transferred into or among CAIR SO₂ Allowance Tracking System accounts in accordance with the requirements of 40 CFR Part 96, Subpart FFF or Subpart GGG.
- (v) A CAIR SO₂ allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO₂ Trading Program. No provision of the CAIR SO₂ Trading Program, the CAIR permit application, the CAIR permit, or an exemption under 40 CFR § 96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
- (vi) A CAIR SO₂ allowance does not constitute a property right.
- (vii) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FFF or Subpart GGG, every allocation, transfer, or deduction of a CAIR SO₂ allowance to or from a CAIR SO₂ unit's compliance account is incorporated automatically in this CAIR permit.

F. SO₂ excess emissions requirements

- (i) If a CAIR SO₂ source emits sulfur dioxides during any control period in excess of the CAIR SO₂ emissions limitation, the owners and operators of the source and each CAIR SO₂ unit at the source shall surrender the CAIR SO₂ allowances required for deduction under 40 CFR § 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law.
- (ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAA, the Clean Air Act, and applicable State law.

G. Recordkeeping and Reporting Requirements

- (i) Unless otherwise provided, the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and the CAIR SO₂ source^x and each CAIR SO₂ unit at the source^x shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time

before the end of 5 years, in writing by the permitting authority or the Administrator.

- (1) The certificate of representation under 40 CFR §§ 96.113 and 96.213 for the CAIR NO_x designated representative for the source and each CAIR NO_x unit and the CAIR SO₂ designated representative for the source and each CAIR SO₂ unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR §§ 96.113 and 96.213 changing the CAIR designated representative.
 - (2) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HH and Subpart HHH, provided that to the extent that these subparts provide for a 3-year period for recordkeeping, the 3-year period shall apply.
 - (3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x Annual Trading Program and CAIR SO₂ Trading Program or relied upon for compliance determinations.
 - (4) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_x Annual Trading Program and CAIR SO₂ Trading Program or to demonstrate compliance with the requirements of the CAIR NO_x Annual Trading Program and CAIR SO₂ Trading Program.
- (ii) The CAIR designated representative of a CAIR NO_x source and each CAIR NO_x unit at the source and a CAIR SO₂ source and each CAIR SO₂ unit at the source shall submit the reports required under the CAIR NO_x Annual Trading Program and the CAIR SO₂ Trading Program including those under 40 CFR Part 96, Subpart HH and Subpart HHH.
- H. The CAIR NO_x source and each CAIR NO_x unit shall meet the requirements of the CAIR NO_x Annual Trading Program contained in 40 CFR Part 96, Subparts AA through II.
- I. The CAIR SO₂ source and each CAIR SO₂ unit shall meet the requirements of the CAIR SO₂ Trading Program contained in 40 CFR Part 96, Subparts AAA through III.
- J. Any provision of the CAIR NO_x Annual Trading Program and the CAIR SO₂ Trading Program that applies to a CAIR NO_x source or CAIR SO₂ source or the CAIR designated representative of a CAIR NO_x source or CAIR SO₂ source shall also apply to the owners and operators of such source and the units at the source.
- K. Any provision of the CAIR NO_x Annual Trading Program and the CAIR SO₂ Trading Program that applies to a CAIR NO_x unit or CAIR SO₂ unit or the CAIR

designated representative of a CAIR NO_x unit or CAIR SO₂ unit shall also apply to the owners and operators of such unit.

- L. No provision of the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, a CAIR permit application, a CAIR permit, or an exemption under 40 CFR §§ 96.105 or 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x source or CAIR NO_x unit or a CAIR SO₂ source or CAIR SO₂ unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Clean Air Interstate Rule Unit Exemptions

- 18. As reference only information, the following unit (BOILER 1) has received a CAIR unit exemption and is not incorporated into the CAIR Permit.

Attachments

Applicable Requirements Summary

Additional Monitoring Requirements

Permit Shield

New Source Review Authorization References

Applicable Requirements Summary

Unit Summary	22
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Note: A “none” entry may be noted for some emission sources in this permit’s “Applicable Requirements Summary” under the heading of “Monitoring and Testing Requirements” and/or “Recordkeeping Requirements” and/or “Reporting Requirements.” Such a notation indicates that there are no requirements for the indicated emission source as identified under the respective column heading(s) for the stated portion of the regulation when the emission source is operating under the conditions of the specified SOP Index Number. However, other relevant requirements pursuant to 30 TAC Chapter 122 including Recordkeeping Terms and Conditions (30 TAC § 122.144), Reporting Terms and Conditions (30 TAC § 122.145), and Compliance Certification Terms and Conditions (30 TAC § 122.146) continue to apply.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
EMGEN1-STK	SRIC ENGINES	N/A	60III	40 CFR Part 60, Subpart III	No changing attributes.
EMGEN1-STK	SRIC ENGINES	N/A	63ZZZZ	40 CFR Part 63, Subpart ZZZZ	No changing attributes.
FWP1-STK	SRIC ENGINES	N/A	60III	40 CFR Part 60, Subpart III	No changing attributes.
FWP1-STK	SRIC ENGINES	N/A	63ZZZZ	40 CFR Part 63, Subpart ZZZZ	No changing attributes.
GRP-CT	STATIONARY TURBINES	CT-1, CT-2	60KKKK-01	40 CFR Part 60, Subpart KKKK	Fuel Quality = Fuel is demonstrated not to exceed emission standard by representative fuel sampling data. 75% of Peak = The combustion turbine operates at less than 75% of peak load or at temperatures less than zero degrees F., 30 MW = The combustion turbine has an output of 30 MW or greater.
GRP-CT	STATIONARY TURBINES	CT-1, CT-2	60KKKK-02	40 CFR Part 60, Subpart KKKK	Fuel Quality = Fuel is demonstrated not to exceed emission standard by characteristics in purchase contract or tariff sheet. 75% of Peak = The combustion turbine operates at less than 75% of peak load or at temperatures less than zero degrees F., 30 MW = The combustion turbine has an output of 30 MW or greater.
GRP-CT	STATIONARY TURBINES	CT-1, CT-2	60KKKK-03	40 CFR Part 60, Subpart KKKK	Fuel Quality = Fuel is demonstrated not to exceed emission standard by representative fuel sampling data. 75% of Peak = The combustion turbine does not operate at less than 75% of peak load or at temperatures less than zero degrees F.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
GRP-CT	STATIONARY TURBINES	CT-1, CT-2	60KKKK-04	40 CFR Part 60, Subpart KKKK	Fuel Quality = Fuel is demonstrated not to exceed emission standard by characteristics in purchase contract or tariff sheet. 75% of Peak = The combustion turbine does not operate at less than 75% of peak load or at temperatures less than zero degrees F.
GRP-STK	Emission Points/Stationary Vents/Process Vents	U1-STK, U2-STK	R1111	30 TAC Chapter 111, Visible Emissions	No changing attributes.

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
EMGEN1-STK	EU	60III	CO	40 CFR Part 60, Subpart III	§ 60.4205(b) § 60.4202(a)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f) § 60.4218 § 89.112(a)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than or equal to 130 KW and less than or equal to 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 model year and later must comply with a CO emission limit of 3.5 g/KW-hr, as stated in 40 CFR 60.4202(a)(2) and 40 CFR 89.112(a).	§ 60.4209(a)	§ 60.4214(b)	None
EMGEN1-STK	EU	60III	NMHC and NO _x	40 CFR Part 60, Subpart III	§ 60.4205(b) § 60.4202(a)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f) § 60.4218 § 89.112(a)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 560 KW and less than or equal to 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 model year and later must comply with an NMHC+NO _x emission limit of 6.4 g/KW-hr, as stated in 40 CFR 60.4202(a)(2) and 40 CFR 89.112(a).	§ 60.4209(a)	§ 60.4214(b)	None
EMGEN1-STK	EU	60III	PM	40 CFR Part 60, Subpart III	§ 60.4205(b) § 60.4202(a)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than or equal to 130 KW and less	§ 60.4209(a)	§ 60.4214(b)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
					[G]§ 60.4211(f) § 60.4218 § 89.112(a)	than or equal to 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 model year and later must comply with a PM emission limit of 0.20 g/KW-hr, as stated in 40 CFR 60.4202(a)(2) and 40 CFR 89.112(a).			
EMGEN1-STK	EU	63ZZZZ	112(B) HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6590(c)	Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines as applicable. No further requirements apply for such engines under this part.	None	None	None
FWP1-STK	EU	60IIII	NMHC and NO _x	40 CFR Part 60, Subpart IIII	§ 60.4205(c)-Table 4 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f) § 60.4218	Owners and operators of emergency stationary fire pump CI ICE with a maximum engine power greater than or equal to 130 KW and less than or equal to 560 KW and a displacement of less than 30 liters per cylinder and is a 2009 model year and later	None	None	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						must comply with an NMHC+NOx emission limit of 4.0 g/KW-hr, as listed in Table 4 to this subpart.			
FWP1-STK	EU	60III	PM	40 CFR Part 60, Subpart III	§ 60.4205(c)-Table 4 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f) § 60.4218	Owners and operators of emergency stationary fire pump CI ICE with a maximum engine power greater than or equal to 130 KW and less than or equal to 560 KW and a displacement of less than 30 liters per cylinder and is a 2009 model year and later must comply with a PM emission limit of 0.20 g/KW-hr, as listed in Table 4 to this subpart.	None	None	None
FWP1-STK	EU	63ZZZZ	112(B) HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6590(c)	Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart III, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines as applicable. No further requirements apply for such engines under this part.	None	None	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
GRP-CT	EU	60KKKK-01	NO _x	40 CFR Part 60, Subpart KKKK	§ 60.4320(a)-Table 1 § 60.4320(a) § 60.4320(b) § 60.4333(a) § 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345	Turbines operating at less than 75 percent of peak load, or turbines operating at temperatures less than 0 degrees F with greater than 30 MW output must meet the nitrogen oxides emission standard of 96 ppm at 15 percent O ₂ .	§ 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345 § 60.4350(a) § 60.4350(b) § 60.4350(c) § 60.4350(d) § 60.4350(e) § 60.4350(f) § 60.4350(h) [G]§ 60.4400(a) § 60.4400(b) § 60.4400(b)(1) § 60.4400(b)(4) § 60.4400(b)(5) § 60.4400(b)(6) [G]§ 60.4405	[G]§ 60.4345 § 60.4350(b)	[G]§ 60.4345 § 60.4350(d) § 60.4375(a) § 60.4380 [G]§ 60.4380(b) § 60.4395
GRP-CT	EU	60KKKK-01	SO ₂	40 CFR Part 60, Subpart KKKK	§ 60.4330(a)(2) § 60.4333(a)	You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO ₂ /J (0.060 lb SO ₂ /MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.	§ 60.4365 § 60.4365(b) § 60.4415(a) § 60.4415(a)(1) § 60.4415(a)(1)(ii)	§ 60.4365(b)	§ 60.4375(a)
GRP-CT	EU	60KKKK-02	NO _x	40 CFR Part 60, Subpart KKKK	§ 60.4320(a)-Table 1 § 60.4320(a) § 60.4320(b) § 60.4333(a) § 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345	Turbines operating at less than 75 percent of peak load, or turbines operating at temperatures less than 0 degrees F with greater than 30 MW output must meet the nitrogen oxides emission standard of 96	§ 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345 § 60.4350(a) § 60.4350(b) § 60.4350(c) § 60.4350(d) § 60.4350(e)	[G]§ 60.4345 § 60.4350(b)	[G]§ 60.4345 § 60.4350(d) § 60.4375(a) § 60.4380 [G]§ 60.4380(b) § 60.4395

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						ppm at 15 percent O ₂ .	§ 60.4350(f) § 60.4350(h) [G]§ 60.4400(a) § 60.4400(b) § 60.4400(b)(1) § 60.4400(b)(4) § 60.4400(b)(5) § 60.4400(b)(6) [G]§ 60.4405		
GRP-CT	EU	60KKKK-02	SO ₂	40 CFR Part 60, Subpart KKKK	§ 60.4330(a)(2) § 60.4333(a)	You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO ₂ /J (0.060 lb SO ₂ /MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.	§ 60.4365 § 60.4365(a) § 60.4415(a) § 60.4415(a)(1) § 60.4415(a)(1)(ii)	§ 60.4365(a)	§ 60.4375(a)
GRP-CT	EU	60KKKK-03	NO _x	40 CFR Part 60, Subpart KKKK	§ 60.4320(a)-Table 1 § 60.4320(a) § 60.4320(b) § 60.4325 § 60.4333(a) § 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345	New, modified, or reconstructed turbine firing natural gas with a heat input at peak load > 850 MMBtu/h must meet the nitrogen oxides emission standard of 15 ppm at 15 percent O ₂ .	§ 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345 § 60.4350(a) § 60.4350(b) § 60.4350(c) § 60.4350(d) § 60.4350(e) § 60.4350(f) § 60.4350(h) [G]§ 60.4400(a) § 60.4400(b) § 60.4400(b)(1) § 60.4400(b)(4) § 60.4400(b)(5) § 60.4400(b)(6)	[G]§ 60.4345 § 60.4350(b)	[G]§ 60.4345 § 60.4350(d) § 60.4375(a) § 60.4380 [G]§ 60.4380(b) § 60.4395

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
							[G]§ 60.4405		
GRP-CT	EU	60KKKK-03	SO ₂	40 CFR Part 60, Subpart KKKK	§ 60.4330(a)(2) § 60.4333(a)	You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO ₂ /J (0.060 lb SO ₂ /MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.	§ 60.4365 § 60.4365(b) § 60.4415(a) § 60.4415(a)(1) § 60.4415(a)(1)(ii)	§ 60.4365(b)	§ 60.4375(a)
GRP-CT	EU	60KKKK-04	NO _x	40 CFR Part 60, Subpart KKKK	§ 60.4320(a)-Table 1 § 60.4320(a) § 60.4320(b) § 60.4325 § 60.4333(a) § 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345	New, modified, or reconstructed turbine firing natural gas with a heat input at peak load > 850 MMBtu/h must meet the nitrogen oxides emission standard of 15 ppm at 15 percent O ₂ .	§ 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345 § 60.4350(a) § 60.4350(b) § 60.4350(c) § 60.4350(d) § 60.4350(e) § 60.4350(f) § 60.4350(h) [G]§ 60.4400(a) § 60.4400(b) § 60.4400(b)(1) § 60.4400(b)(4) § 60.4400(b)(5) § 60.4400(b)(6) [G]§ 60.4405	[G]§ 60.4345 § 60.4350(b)	[G]§ 60.4345 § 60.4350(d) § 60.4375(a) § 60.4380 [G]§ 60.4380(b) § 60.4395
GRP-CT	EU	60KKKK-04	SO ₂	40 CFR Part 60, Subpart KKKK	§ 60.4330(a)(2) § 60.4333(a)	You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO ₂ /J (0.060 lb SO ₂ /MMBtu) heat	§ 60.4365 § 60.4365(a) § 60.4415(a) § 60.4415(a)(1) § 60.4415(a)(1)(ii)	§ 60.4365(a)	§ 60.4375(a)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.			
GRP-STK	EP	R1111	OPACITY	30 TAC Chapter 111, Visible Emissions	§ 111.111(a)(1)(C) § 111.111(a)(1)(E)	Visible emissions from any stationary vent shall not exceed an opacity of 15% averaged over a six minute period for any source with a total flow rate of at least 100,000 acfm unless a CEMS is installed.	[G]§ 111.111(a)(1)(F) ** See Periodic Monitoring Summary	None	None

Additional Monitoring Requirements

Periodic Monitoring Summary 32

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: GRP-STK	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
<p>Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.</p> <p>Periodic Monitoring Text: Record the type of fuel used by the unit. If an alternate fuel is fired, either alone or in combination with the specified gas, for a period greater than or equal to 24 consecutive hours it shall be considered and reported as a deviation or the permit holder shall conduct an observation of the stationary vent for each such period to determine if visible emissions are observed. Any time an alternate fuel is fired for a period of greater than 7 consecutive days then visible emissions observations will be conducted no less than once per week. Documentation of all observations shall be maintained. If visible emissions are present during the firing of an alternate fuel, the permit holder shall either list this occurrence as a deviation or the permit holder may determine the opacity consistent with Test Method 9. Any opacity readings that are above the opacity limit from the underlying applicable requirement shall be reported as a deviation.</p>	

Permit Shield

Permit Shield 34

Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit/Group/Process		Regulation	Basis of Determination
ID No.	Group/Inclusive Units		
GRP-CT	CT-1, CT-2	40 CFR Part 60, Subpart GG	Combustion turbines constructed after 02/18/2005 and are subject to NSPS KKKK.
GRP-CT	CT-1, CT-2	40 CFR Part 63, Subpart YYYY	Source is not major for HAPs.
GRP-TANK	DSL-TK1, DSL-TK2	40 CFR Part 60, Subpart Kb	Tanks capacities are less than 19,800 gallons.
PAINTING	N/A	40 CFR Part 63, Subpart MMMM	The site is not a major source of hazardous air pollutants.

New Source Review Authorization References

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New Source Review Authorization References by Emission Unit	37

New Source Review Authorization References

The New Source Review authorizations listed in the table below are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: PSDTX1244	Issuance Date: 05/27/2016
PSD Permit No.: GHGPSDTX1*	Issuance Date: 11/10/2011
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits By Rule, PSD Permits, or NA Permits) for the Application Area.	
Authorization No.: 93938	Issuance Date: 05/27/2016
Permits By Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.227	Version No./Date: 09/04/2000
Number: 106.244	Version No./Date: 09/04/2000
Number: 106.263	Version No./Date: 11/01/2001
Number: 106.265	Version No./Date: 09/04/2000
Number: 106.371	Version No./Date: 09/04/2000
Number: 106.372	Version No./Date: 09/04/2000
Number: 106.454	Version No./Date: 11/01/2001
Number: 106.472	Version No./Date: 09/04/2000
Number: 106.473	Version No./Date: 09/04/2000
Number: 106.476	Version No./Date: 09/04/2000
Number: 106.511	Version No./Date: 09/04/2000
Number: 106.532	Version No./Date: 09/04/2000
Number: 75	Version No./Date: 06/07/1996
Number: 102	Version No./Date: 06/07/1996

*For reference, EPA issued permit PSD-TX-1244-GHG has been assigned TCEQ permit number GHGPSDTX1.

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization
CT-1	COMBUSTION TURBINE 1	93938, PSDTX1244
CT-2	COMBUSTION TURBINE 2	93938, PSDTX1244
DSL-TK1	DIESEL TANK 1	93938, PSDTX1244
DSL-TK2	DIESEL TANK 2	93938, PSDTX1244
EMGEN1-STK	EMERGENCY GENERATOR	93938, PSDTX1244, GHGPSDTX1
FWP1-STK	FIRE WATER PUMP	93938, PSDTX1244, GHGPSDTX1
PAINTING	MAINTENANCE PAINTING OPERATIONS	106.263/11/01/2001
U1-STK	COMBUSTION TURBINE 1 STACK	93938, PSDTX1244, GHGPSDTX1
U2-STK	COMBUSTION TURBINE 2 STACK	93938, PSDTX1244, GHGPSDTX1

Appendix A

Acronym List	39
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Acronym List

The following abbreviations or acronyms may be used in this permit:

ACFM	actual cubic feet per minute
AMOC	alternate means of control
ARP	Acid Rain Program
ASTM	American Society of Testing and Materials
B/PA	Beaumont/Port Arthur (nonattainment area)
CAM	Compliance Assurance Monitoring
CD	control device
COMS	continuous opacity monitoring system
CVS	closed-vent system
D/FW	Dallas/Fort Worth (nonattainment area)
DR	Designated Representative
ELP	El Paso (nonattainment area)
EP	emission point
EPA	U.S. Environmental Protection Agency
EU	emission unit
FCAA Amendments	Federal Clean Air Act Amendments
FOP	federal operating permit
GF	grandfathered
gr/100 scf	grains per 100 standard cubic feet
HAP	hazardous air pollutant
H/G/B	Houston/Galveston/Brazoria (nonattainment area)
H ₂ S	hydrogen sulfide
ID No.	identification number
lb/hr	pound(s) per hour
MMBtu/hr	Million British thermal units per hour
MRRT	monitoring, recordkeeping, reporting, and testing
NA	nonattainment
N/A	not applicable
NADB	National Allowance Data Base
NO _x	nitrogen oxides
NSPS	New Source Performance Standard (40 CFR Part 60)
NSR	New Source Review
ORIS	Office of Regulatory Information Systems
Pb	lead
PBR	Permit By Rule
PM	particulate matter
ppmv	parts per million by volume
PSD	prevention of significant deterioration
RO	Responsible Official
SO ₂	sulfur dioxide
TCEQ	Texas Commission on Environmental Quality
TSP	total suspended particulate
TVP	true vapor pressure
U.S.C.	United States Code
VOC	volatile organic compound

Appendix B

Major NSR Summary Table	41
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Major NSR Summary Table

Permit Number: 93938 / PSDTX1244			Issuance Date: 05/27/2016				
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lbs/hour	TPY (4)	Spec. Cond.	Spec. Cond.	Spec. Cond.
U1-STK	GE 7FA (~195 MW)	NO _x (6)	18.80	73.50	2, 7, 8, 16, 17, 18, 19	2, 8, 16, 17, 18, 19, 20, 21	2, 16, 17, 18, 22
		NO _x (MSS) (6)	160.00	--			
		CO (6)	16.82	176.30			
		CO (MSS) (6)	1800.00	--			
		VOC	4.82	33.91			
		VOC (MSS)	69.98	--			
		SO ₂	27.07	10.87			
		PM	33.43	73.10			
		PM ₁₀	33.43	73.10			
		PM _{2.5}	33.43	73.10			
		H ₂ SO ₄	13.68	5.49			
		NH ₃	17.89	71.84			
U2-STK	GE 7FA (~195 MW)	NO _x (6)	18.80	73.50	2, 7, 8, 16, 17, 18, 19	2, 8, 16, 17, 18, 19, 20, 21	2, 16, 17, 18, 22
		NO _x (MSS) (6)	160.00	--			
		CO (6)	16.82	176.30			
		CO (MSS) (6)	1800.00	--			
		VOC	4.82	33.91			
		VOC (MSS)	69.98	--			
		SO ₂	27.07	10.87			
		PM	33.43	73.10			
		PM ₁₀	33.43	73.10			
		PM _{2.5}	33.43	73.10			
		H ₂ SO ₄	13.68	5.49			
		NH ₃	17.89	71.84			

Major NSR Summary Table

Permit Number: 93938 / PSDTX1244							
Issuance Date: 05/27/2016							
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lbs/hour	TPY (4)	Spec. Cond.	Spec. Cond.	Spec. Cond.
CT1LOV-VNT	Combustion Turbine 1 Lube Oil Vent	VOC	0.09	0.40	8	8, 20, 21	
		PM	0.09	0.40			
		PM ₁₀	0.09	0.40			
		PM _{2.5}	0.09	0.40			
CT2LOV-VNT	Combustion Turbine 2 Lube Oil Vent	VOC	0.09	0.40	8	8, 20, 21	
		PM	0.09	0.40			
		PM ₁₀	0.09	0.40			
		PM _{2.5}	0.09	0.40			
ST1LOV-VNT	Steam Turbine 1 Lube Oil Vent	VOC	0.09	0.40	8	8, 20, 21	
		PM	0.09	0.40			
		PM ₁₀	0.09	0.40			
		PM _{2.5}	0.09	0.40			
CT1GSOV-VNT	Combustion Turbine 1 Generator Seal Oil Vent	VOC	0.09	0.40		20	
CT2GSOV-VNT	Combustion Turbine 2 Generator Seal Oil Vent	VOC	0.09	0.40		20	
ST1SOV-VNT	Steam Turbine Generator 1 Seal Oil Vent	VOC	0.09	0.40		20	
DSL-TK1	Diesel Tank 1	VOC	0.07	<0.01		20	
DSL-TK2	Diesel Tank 2	VOC	0.02	<0.01		20	
NG-FUG	Natural Gas Fugitives (5)	VOC	0.03	0.12		20	
NH3-FUG	Ammonia Fugitives (5)	NH ₃	0.12	0.51	10	20, 21	

Major NSR Summary Table

Permit Number: 93938 / PSDTX1244							
Issuance Date: 05/27/2016							
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lbs/hour	TPY (4)	Spec. Cond.	Spec. Cond.	Spec. Cond.
EMGEN1-STK	Emergency Generator	NO _x	16.52	0.83	2, 3, 7, 8	2, 3, 6, 8, 20, 21	2, 3
		CO	9.65	0.48			
		VOC	0.89	0.04			
		PM	0.55	0.03			
		PM ₁₀	0.55	0.03			
		PM _{2.5}	0.55	0.03			
		SO ₂	<0.01	<0.01			
FWP1-STK	Fire Water Pump	NO _x	3.81	0.19	2, 3, 7, 8	2, 3, 6, 8, 20, 21	2, 3
		CO	4.12	0.21			
		VOC	0.27	0.01			
		PM	0.20	0.01			
		PM ₁₀	0.20	0.01			
		PM _{2.5}	0.20	0.01			
		SO ₂	<0.01	<0.01			
TURB-MSS	ILE Turbine Maintenance Fugitives	PM	0.09	0.02	8, 14	8, 13, 20, 21	
		PM ₁₀	0.09	0.02			
		PM _{2.5}	<0.01	<0.01			
		NH ₃	<0.01	<0.01			
GASVENT	Natural Gas Venting	VOC	9.72	0.64	14	13, 20, 21	
MISC-MSS	Planned site-wide MSS activities (5)	VOC	0.55	0.02	14	13, 20, 21	
		NO _x	<0.01	<0.01			
		CO	<0.01	<0.01			

Footnotes:

- (1) Emission point identification - either specific equipment designation or emission point number from plot plan.
- (2) Specific point source name. For fugitive sources, use area name or fugitive source name.
- (3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code §101.1
 - NO_x - total oxides of nitrogen
 - SO₂ - sulfur dioxide
 - PM - total particulate matter, suspended in the atmosphere, including PM₁₀ and PM_{2.5}, as represented
 - PM₁₀ - total particulate matter equal to or less than 10 microns in diameter, including PM_{2.5}, as represented
 - PM_{2.5} - particulate matter equal to or less than 2.5 microns in diameter
 - CO - carbon monoxide
 - H₂SO₄ - sulfuric acid
 - NH₃ - ammonia
- (4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
- (5) Emission rate is an estimate and is enforceable through compliance with the applicable special conditions(s) and permit application representations.
- (6) For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply.

Major NSR Summary Table

Permit Number: GHGPSDTX1 (Issuance Date: 11/10/2011)							
Em. Point No.	Source Name	Air Contaminant Name	CO ₂ e Emission Rates		Monitoring & Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lb/hr ¹	TPY CO ₂ e ^{2,3}			
U1-STK	Unit 1 of 2 Natural Gas Fired General Electric 7Fa Combustion Turbines	CO ₂		908,957.6	II.B.1., II.B.2., II.B.3., II.B.4., V	II.B.3., II.B.4., III.A, III.B, III.C, III.D, III.H	II.B.3., III.E, III.F, III.G, V.B
		CH ₄		353.3			
		N ₂ O		521.6			
U2-STK	Unit 2 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO ₂		908,957.6	II.B.1., II.B.2., II.B.3., II.B.4., V	II.B.3., II.B.4., III.A, III.B, III.C, III.D, III.H	II.B.3., III.E, III.F, III.G, V.B
		CH ₄		353.3			
		N ₂ O		521.6			
NG-FUG	Fugitive Natural Gas emissions from piping components	CH ₄		327.2	II.D.2.	III.A, III.B, III.C, III.D, III.H, II.D.2.	III.E, III.F, III.G
EMGE N1-STK	1,340-hp Diesel Fired Emergency Generator	CO ₂ ^{5,6}	15,314.0 ¹	765.7	II.C.2.	II.C.2., III.A, III.B, III.C, III.D, III.H	III.E, III.F, III.G
FWP1-STK	617-hp Diesel Fired Fire Water Pump	CO ₂ ^{5,6}	7,052.0 ¹	352.6	II.C.2.	II.C.2., III.A, III.B, III.C, III.D, III.H	III.E, III.F, III.G
SF6-FUG	SF ₆ Insulated Electrical Equipment	SF ₆		131.0	II.D.2.	III.A, III.B, III.C, III.D, III.H, II.D.2.	III.E, III.f, III.G

1. Compliance with the short term emission limits (pounds per hour) is based on a 30-day rolling average.
2. Compliance with annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during normal operations and startup and shutdown activities.

4. Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emission (CO_2) is not presented in the table.
5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions (CH_4 and N_2O) are not presented in the table.
6. Hours of operation for emission units EMGEN1-STK and FWP1-STK shall not exceed 100 hours of non-emergency only operation per year.



Texas Commission on Environmental Quality Air Quality Permit

A Permit Is Hereby Issued To
Lower Colorado River Authority
Authorizing the Construction and Operation of
Thomas C. Ferguson Power Plant
Located at Horseshoe Bay, Llano County, Texas
Latitude 30° 33' 27" Longitude -98° 22' 23"

Permits: 93938 and PSDTX1244

Revision Date: May 27, 2016

Expiration Date: September 1, 2021

A handwritten signature in black ink, appearing to read "R. D. A. Hyle".

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code (TAC) Section 116.116 (30 TAC § 116.116)]¹
2. **Voiding of Permit.** A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1) the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of \$5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC § 116.120]
3. **Construction Progress.** Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC § 116.115(b)(2)(A)]
4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC § 116.115(b)(2)(B)]
5. **Sampling Requirements.** If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling

facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC § 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC § 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction in a timely manner; comply with any additional recordkeeping requirements specified in special conditions in the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC § 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled “Emission Sources--Maximum Allowable Emission Rates.” [30 TAC § 116.115(b)(2)(F)]¹
9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification in accordance with 30 TAC §101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC§ 116.115(b)(2)(G)]
10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC § 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC § 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC § 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to “air pollution” as defined in Texas Health and Safety Code (THSC) §382.003(3) or violate THSC § 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.¹

¹ Please be advised that the requirements of this provision of the general conditions may not be applicable to greenhouse gas emissions.

Special Conditions

Permit Numbers 93938 and PSDTX1244

1. This permit authorizes emissions only from those emission points listed in the attached table entitled “Emission Sources - Maximum Allowable Emission Rates” (MAERT), and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit. Also, this permit authorizes the emissions from the planned maintenance, startup, and shutdown (MSS) activities listed in Attachment A, Attachment B, or the MAERT attached to this permit. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. Attachment B identifies the planned maintenance activities that are non-ILE planned maintenance activities that this permit authorizes to be performed.

Federal Applicability

2. These facilities shall comply with the applicable requirements of Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):
 - A. Subpart A: General Provisions.
 - B. Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
 - C. Subpart KKKK: Standards of Performance for Stationary Combustion Turbines.
3. These facilities shall comply with the applicable requirements of 40 CFR Part 63:
 - A. Subpart A: General Provisions.
 - B. Subpart ZZZZ: National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Emission Standards and Operating Specifications

4. This permit authorizes two General Electric 7FA (GE 7FA) natural gas fired combustion turbine generators (CTGs), Emission Point Nos. [EPNs] U1-STK and U2-STK, each rated at a maximum base-load electric output of approximately 195 megawatts (MW) and operating in combined cycle with its heat recovery steam generator (HRSG).
5. Emission Rates.
 - A. The concentration of nitrogen oxides (NO_x) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 2 parts per million by volume dry (ppmvd) corrected to 15 percent oxygen (O₂), on a rolling 24-hour average, subject to the following specifications: **(10/15)**
 - (1) A valid hour consists of a minimum of 4, and normally 60, approximately equally-spaced data points.

- (2) Excess emissions during initial or other major dry low NO_x burner tuning sessions are excluded. Major tuning sessions are scheduled events, and would occur after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.
- B. The concentration of carbon monoxide (CO) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 4 ppmvd corrected to 15 percent O₂, on a rolling three-hour average, for load operations at 60 percent or above.
- C. The concentration of CO from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 6 ppmvd corrected to 15 percent O₂, on a rolling three-hour average, for load operations below 60 percent.
- D. The concentration of volatile organic compounds (VOC) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 2 ppmvd corrected to 15 percent O₂, on a three-hour average.
- E. The concentration of ammonia (NH₃) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 7 ppmvd corrected to 15 percent O₂, on a rolling 24-hour average.

The concentrations above do not apply during periods of turbine MSS activities.

- 6. Also authorized under this permit are an Emergency Generator (EPN EMGEN1-STK) not to exceed 1340 horsepower (hp) and a Fire Water Pump (EPN FWP1-STK) not to exceed 617 hp. The Emergency Generator and Fire Water Pump are each limited to 100 hours of operation per year for non-emergency operation. **(4/14)**

7. Fuel Specifications.

- A. Fuel for the CTGs is limited to pipeline-quality natural gas containing no more than 5 grains total sulfur per 100 dry standard cubic feet on an hourly basis and 0.50 grain total sulfur per 100 dry standard cubic feet on an annual basis.
- B. The Emergency Generator (EPN EMGEN1-STK) and the Fire Water Pump (EPN E-PUMP2) are authorized to fire diesel fuel containing no more than 0.05 percent sulfur by weight.

Upon request by the Executive Director of the TCEQ or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel-fired in the CTGs, emergency generator, and fire water pump, or shall allow air pollution control agency representatives to obtain a sample for analysis.

- 8. Except during MSS activities, the opacity shall not exceed five percent averaged over a six-minute period from each stack or vent. During MSS activities, the opacity shall not exceed 15 percent. Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this

condition. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations or 15 percent during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

Aqueous Ammonia (NH₃)

9. The permit holder shall maintain prevention and protection measures for the NH₃ storage system. The NH₃ storage tank area will be marked and protected so as to protect the NH₃ storage area from accidents that could cause a rupture. The aqueous ammonia stored shall have a concentration of less than 20 percent NH₃ by weight.
10. In addition to the requirements of Special Condition No. 9, the permit holder shall maintain the piping and valves in NH₃ service as follows:
 - A. All operating practices and procedures relating to the handling and storage of NH₃ shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.
 - B. Audio, visual, and olfactory (AVO) checks for NH₃ leaks shall be made once a day.
 - C. As soon as possible, following the detection of a leak, plant personnel shall take one or more of the following actions:
 - (1) Locate and isolate the leak, if necessary.
 - (2) Commence repair or replacement of the leaking component.
 - (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Planned Maintenance, Startup, and Shutdown

11. The holder of this permit shall minimize emissions during planned MSS activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.
12. Emissions during planned startup and shutdown activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows:
 - A. A planned startup of each CTG (EPNs: U1-STK and U2-STK) is defined as the period that begins when there is measurable fuel flow to the CTG and ends when the CTG load reaches 50 percent. A planned startup for each CTG is limited to 360 minutes. At the conclusion of the startup period (the CTG load reaches 50 percent or 360 minutes, whichever comes first), the permit holder shall comply with the emission rates limitations in Special Condition No. 5 and the MAERT. **(4/14)**

- B. A planned shutdown of each CTG (EPNs: U1-STK and U2-STK) is defined as the period that begins when the Data Acquisition and Handling System (DAHS) receives a shutdown signal from the turbine controller and CTG load falls below 50 percent and ends when there is no longer measureable fuel flow to the CTG. A planned shutdown for each CTG is limited to 60 minutes. **(4/14)**
13. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit may be demonstrated as follows.
- A. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
 - B. For each pollutant emitted through a stack during non-ILE planned maintenance activities (See Attachment B), where emissions are measured using a CEMS per Special Condition No. 14A, the permit holder shall compare the pollutant's short-term (hourly) emissions during planned maintenance activities (as measured by the CEMS) to the applicable short-term planned MSS emissions limit in the MAERT for each calendar month.
 - C. For each pollutant emitted through a stack during non-ILE planned maintenance activities (See Attachment B), where emissions are not measured using a CEMS, the permit holder shall determine the total emissions of the pollutant through the stack that result from such non-ILE planned maintenance activities in accordance with Special Condition No. 14B for each calendar month.
 - D. For each pollutant that is not emitted through a stack during non-ILE planned maintenance activities (See Attachment B), the permit holder shall determine the total emissions of the pollutant from such non-ILE planned maintenance activities in accordance with Special Condition No. 14B, for each calendar month.
14. The permit holder shall determine the emissions during planned MSS activities for use in Special Condition No. 13 as follows.
- A. For each pollutant where emissions (during normal facility operations) are measured with a CEMS that has been certified to measure the pollutant's emissions over the entire range of a planned MSS activity, the permit holder shall measure the emissions of the pollutant during the planned MSS activity using the CEMS.
 - B. For each pollutant not described in Special Condition No. 14A, the permit holder shall calculate the pollutant's emissions during all occurrences of each type of planned MSS activity for each calendar month using the frequency of the planned MSS activity identified in work orders or equivalent records and the emissions of the pollutant during the planned MSS activity, as represented in the planned MSS permit application. In lieu of using the emissions of the pollutant during the planned MSS activity as represented in the planned MSS permit application to calculate such

emissions, the permit holder may determine the emissions of the pollutant during the planned MSS activity using an appropriate method, including but not limited to, any of the methods described in paragraphs 1 through 4 below, provided that the permit holder maintains appropriate records supporting such determination:

- (1) Use of emission factor(s), facility-specific parameter(s), and/or engineering knowledge of the facility's operations.
- (2) Use of emissions data measured (by a CEMS or during emissions testing) during the same type of planned MSS activity occurring at or on a similar facility, and correlation of that data with the facility's relevant operating parameters, including, but not limited to, electric load, temperature, fuel input, and fuel sulfur content.
- (3) Use of emissions testing data collected during a planned MSS activity occurring at or on the facility, and correlation of that data with the facility's relevant operating parameters, including, but not limited to, electric load, temperature, fuel input, and fuel sulfur content.
- (4) Use of parametric emissions monitoring system (PEMS) data applicable to the facility.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.
16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs U1-STK and U2-STK and to determine initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Test Methods 201A and 202 or Test Method 5, modified for the concentration of particulate matter less than 10 microns in diameter (PM_{10}); Test Method 8 or Test Methods 6 or 6C for sulfur dioxide (SO_2); Test Method 9 for opacity; Test Method 10 for the concentration of CO; and Test Method 25A, modified to exclude methane and ethane, for the concentration of VOC. In addition, Test Method 20 or equivalent methods shall be used to determine the concentrations of NO_x and O_2 for the CTGs.

Fuel sampling (for EPNs U1-STK and U2-STK) using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2 or the permit holder may be exempted from fuel monitoring of SO_2 as provided under 40 CFR § 60.4365(a). If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart KKKK, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2 . Any deviations from those procedures must be approved by the Executive

Director of the TCEQ prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

- A. The TCEQ Austin Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

- (1) Date for pretest meeting.
- (2) Date sampling will occur.
- (3) Name of firm conducting sampling.
- (4) Type of sampling equipment to be used.
- (5) Method or procedure to be used in sampling.
- (6) Procedure used to determine turbine loads during and after the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions, or the TCEQ or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate or equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

- B. Air contaminants and diluents to be sampled and analyzed include (but are not limited to) NO_x, O₂, CO, VOC, SO₂, PM₁₀, and NH₃. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 or 40 CFR § 60.4365(a) may be conducted for monitoring SO₂.
- C. Each turbine shall be tested at or above 90 percent of maximum load operations. Also, each turbine shall be tested below 60 percent of maximum load operations but above 45 percent of maximum load operations. Each tested turbine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.
- D. Sampling as required by this condition shall occur within 60 days after achieving the maximum production rate at which each turbine will be operated, but no later than

180 days after initial start-up of each unit. Additional sampling may be required by TCEQ or EPA.

- E. Within 60 days after the completion of the testing and sampling required herein, two copies of the sampling reports shall be distributed as follows:

One copy to the TCEQ Austin Regional Office.

One copy to the EPA Region 6 Office, Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NO_x, CO, and diluents (O₂ or CO₂) from each Stack (EPNs U1-STK and U2-STK).
- A. Monitored NO_x and CO concentrations shall be corrected and reported in dimensional units corresponding to the emission rate and concentration limits established in this permit.
 - B. The CEMS data shall be used to demonstrate compliance with the emission limitations in Special Condition No. 5 and the MAERT.
 - C. The NO_x/diluent CEMS shall be operated according to the methods and procedures as set out in 40 CFR § 60.4345.
 - D. The CO CEMS shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Each CO monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters if four successive quarterly CGA have been conducted for that four-quarter period. An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur at least two months apart.
 - E. Reporting of monitoring data for demonstrating compliance with NSPS Subpart KKKK and this permit shall be conducted in accordance with the methods and procedures as set out in 40 CFR § 60.4380(b).
 - F. Compliance with the NO_x/diluent continuous emissions monitor requirements above can be demonstrated by meeting the requirements of 40 CFR Part 75 provided that the permit holder demonstrates compliance with applicable NSPS regulations.
 - G. The TCEQ Austin Regional Office shall be notified at least 21 days prior to any required relative accuracy test audit in order to provide them the opportunity to observe the testing.
18. The holder of this permit shall continuously monitor ammonia emissions from EPNs U1-STK and U2-STK when their respective SCR is in operation using one of the following methods. The NH₃ concentrations shall be corrected and reported in accordance with Special Condition No. 5. Monitor downtime shall not exceed 5 percent of the time that the

HRSs were operated over the previous 12-month rolling period. Downtime consists of activities involving calibration, unanticipated power failure, unanticipated equipment malfunction, unplanned maintenance and planned maintenance.

- A. Install and operate an additional NO_x CEMS located upstream of each SCR system, which will be used in association with the NO_x CEMS located downstream of each SCR system, the NH₃ injection rate, and the following calculation procedure to estimate NH₃ slip:

$$\text{NH}_3 \text{ slip, ppmvd} = (a - (b \times c / 1,000,000)) \times (1,000,000 / b) \times d$$

where:

a = ammonia injection rate pound per hour (lb/hr)/17 pound per pound mol (lb/lb-mole);

b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb-mole);

c = change in measured NO_x concentration, ppmvd at 15 percent O₂, across catalyst; and

d = appropriate correction factor.

The correction factor shall be derived during compliance testing by comparing the measured and calculated ammonia slip. The ammonia inject rate and exhaust gas flow rate shall be recorded at least once every 15 minutes and be recorded as hourly averages. Each flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least annually, whichever is more frequent, and shall be accurate to within 2 percent of span or 5 percent of the design value.

- B. Install and operate a dual stream system of NO_x CEMS at the exit of each SCR system. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through an NH₃ converter to convert NH₃ to NO_x and then to a second NO_x CEMS. The NH₃ slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted).
- C. Install an ammonia CEMS. Each ammonia CEMS shall be audited at least once each calendar quarter and shall be designed and operated in accordance with manufacturer specifications.
19. The permit holder shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly natural gas consumption of each CTG. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75, Appendix D.

Recordkeeping Requirements

20. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:
 - A. A copy of this permit.
 - B. Permit application dated October 29, 2010, and subsequent representations submitted to the TCEQ.
 - C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 16 to demonstrate initial compliance.
 - D. Stack sampling results or other air emissions testing (other than CEMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.
21. The following information shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:
 - A. The CEMS data of NO_x, CO, and O₂ emissions from EPNs U1-STK and U2-STK to demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 5.
 - B. Raw data files of all CEMS data including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.
 - C. Records of the hours of operations and sulfur content of diesel fuel fired in the Emergency Generator and Fire Water Pump, pursuant to Special Condition Nos. 6 and 7.
 - D. Records of the sulfur content of natural gas fired in the CTGs pursuant to Special Condition No. 7.
 - E. Records of visible emissions and opacity observations pursuant to Special Condition No. 8.
 - F. Records of ammonia concentration, AVO checks, and maintenance performed to any piping and valves in NH₃ service pursuant to Special Condition Nos. 9 and 10.
 - G. Records of accidental releases, spills, or venting of NH₃ and the corrective action taken.
 - H. Records of NH₃ monitoring pursuant to Special Condition No. 18.
 - I. Records of MSS activities and validations pursuant to Special Condition Nos. 12, 13 and 14.

Reporting

22. The holder of this permit shall submit to the TCEQ Austin Regional Office and the Air Enforcement Branch of EPA in Dallas reports as described in 40 CFR § 60.7. Such reports are required for each emission unit which is required to be continuously monitored pursuant to this permit.

Date: October 12, 2015

Attachment A

Permit Numbers 93938 and PSDTX1244

Inherently Low Emitting (ILE) Planned Maintenance Activities

Planned Maintenance Activity	Emissions					
	NH ₃ /urea	VOC	NO _x	CO	PM	SO ₂
Turbine Air Intake Filter Maintenance					X	
Catalyst Handling and Maintenance ¹					X	
Turbine Washing - Unit Online ²					X	
Ammonia Equipment Maintenance ³	X					
Sludge Management ⁴		X				
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS			X	X		
Small equipment and fugitive component repair/replacement in VOC. ⁵		X				

Notes:

1. Includes, but is not limited to, replacement, cleaning, activation, and deactivation of SCR and oxidation catalysts.
2. Involves use of water only.
3. Includes, but is not limited to, (i) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters and screens in ammonia service and (ii) off-line NO_x control device maintenance (including maintenance of the aqueous ammonia systems associated with the SCR systems).
4. Includes, but is not limited to, management by vacuum truck/dewatering of materials in open pits and ponds, and sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.
5. Includes, but is not limited to, (i) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters and screens in natural gas, fuel oil, diesel oil, ammonia, lube oil, and gasoline service, and (ii) vehicle and mobile equipment maintenance that may involve small VOC emissions, such as oil changes, transmission service, and hydraulic system service.

Date: October 12, 2015

Attachment B

Permit Numbers 93938 and PSDTX1244

Non-Inherently Low Emitting (non-ILE) Planned Maintenance Activities

Planned Maintenance Activity	EPN	Emissions					
		NH ₃ / urea	VOC	NO _x	CO	PM	SO ₂
Combustion Turbine Optimization ¹	U1-STK and U2-STK	x	x	x	x	x	x
NO _x Control Device Maintenance - Unit Online	U1-STK and U2-STK	x		x			
Gaseous Fuel Venting	GASVENT		x				

Note:

1. Includes, but is not limited to, (i) leak and operability checks (e.g., turbine over-speed tests, troubleshooting), (ii) balancing, and (iii) tuning activities that occur during seasonal tuning or after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.

Date: October 12, 2015

Emission Sources - Maximum Allowable Emission Rates

Permit Number 93938 and PSDTX1244

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
U1-STK	GE 7FA (~ 195 MW)	NO _x (6)	18.80	73.50
		NO _x (MSS) (6)	160.00	--
		CO (6)	16.82	176.30
		CO (MSS) (6)	1800.00	--
		VOC	4.82	33.91
		VOC (MSS)	69.98	--
		SO ₂	27.07	10.87
		PM	33.43	73.10
		PM ₁₀	33.43	73.10
		PM _{2.5}	33.43	73.10
		H ₂ SO ₄	13.68	5.49
		NH ₃	17.89	71.84
U2-STK	GE 7FA (~ 195 MW)	NO _x (6)	18.80	73.50
		NO _x (MSS) (6)	160.00	--
		CO (6)	16.82	176.30
		CO (MSS) (6)	1800.00	--
		VOC	4.82	33.91
		VOC (MSS)	69.98	--
		SO ₂	27.07	10.87
		PM	33.43	73.10
		PM ₁₀	33.43	73.10
		PM _{2.5}	33.43	73.10
		H ₂ SO ₄	13.68	5.49

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NH ₃	17.89	71.84
CT1LOV-VNT	Combustion Turbine 1 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM ₁₀	0.09	0.40
		PM _{2.5}	0.09	0.40
CT2LOV-VNT	Combustion Turbine 2 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM ₁₀	0.09	0.40
		PM _{2.5}	0.09	0.40
ST1LOV-VNT	Steam Turbine 1 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM ₁₀	0.09	0.40
		PM _{2.5}	0.09	0.40
CT1GSOV-VNT	Combustion Turbine 1 Generator Seal Oil Vent	VOC	0.09	0.40
CT2GSOV-VNT	Combustion Turbine 2 Generator Seal Oil Vent	VOC	0.09	0.40
ST1SOV-VNT	Steam Turbine Generator 1 Seal Oil Vent	VOC	0.09	0.40
DSL-TK1	Diesel Tank 1	VOC	0.07	<0.01
DSL-TK2	Diesel Tank 2	VOC	0.02	<0.01
NG-FUG	Natural Gas Fugitives (5)	VOC	0.03	0.12
NH ₃ -FUG	Ammonia Fugitives (5)	NH ₃	0.12	0.51
EMGEN1-STK	Emergency Generator	NO _x	16.52	0.83
		CO	9.65	0.48
		VOC	0.89	0.04

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	0.55	0.03
		PM ₁₀	0.55	0.03
		PM _{2.5}	0.55	0.03
		SO ₂	<0.01	<0.01
FWP1-STK	Fire Water Pump	NO _x	3.81	0.19
		CO	4.12	0.21
		VOC	0.27	0.01
		PM	0.20	0.01
		PM ₁₀	0.20	0.01
		PM _{2.5}	0.20	0.01
		SO ₂	<0.01	<0.01
TURB-MSS	ILE Turbine Maintenance Fugitives (5)	PM	0.09	0.02
		PM ₁₀	0.09	0.02
		PM _{2.5}	<0.01	<0.01
		NH ₃	<0.01	<0.01
GASVENT	Natural Gas Venting	VOC	9.72	0.64
MISC-MSS	Planned site-wide MSS activities (5)	VOC	0.55	0.02
		NO _x	<0.01	<0.01
		CO	<0.01	<0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.

(2) Specific point source name. For fugitive sources, use area name or fugitive source name.

(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1

NO_x - total oxides of nitrogen

SO₂ - sulfur dioxide

PM - total particulate matter, suspended in the atmosphere, including PM₁₀ and PM_{2.5}, as represented

PM₁₀ - total particulate matter equal to or less than 10 microns in diameter, including PM_{2.5}, as represented

PM_{2.5} - particulate matter equal to or less than 2.5 microns in diameter

CO - carbon monoxide

Emission Sources - Maximum Allowable Emission Rates

H₂SO₄ - sulfuric acid

NH₃ - ammonia

- (4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
- (5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
- (6) For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply.

Date: October 12, 2015

**PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
FOR GREENHOUSE GAS EMISSIONS
ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21**

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER: PSD-TX-1244-GHG

PERMITTEE: Lower Colorado River Authority (LCRA)
P.O. Box 220
Austin, TX 78767-0220

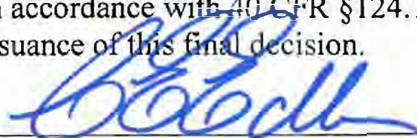
FACILITY NAME: Lower Colorado River Authority (LCRA)
Thomas C. Ferguson Power Plant

FACILITY LOCATION: 2001 Ferguson Road
Horseshoe Bay, TX 78657

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. Seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to the Lower Colorado River Authority (LCRA) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new approximately 590 megawatt (MW) natural gas-fired combined-cycle power plant to replace the existing power generation at the existing facility located in Horseshoe Bay, Texas.

LCRA is authorized to construct the LCRA, Thomas C. Ferguson power plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSDTX1244. Failure to comply with any condition or term set forth in this PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD Permit does not relieve LCRA of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR §124.15(b)(3), this PSD Permit becomes effective immediately upon issuance of this final decision.



Carl E. Edlund, Director
Multimedia Planning and Permitting Division

11/10/11

Date

LCRA, Thomas C. Ferguson Power Plant (PSD-TX-1244-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

The proposed facility is a natural gas-fired combined-cycle electric generating unit at the Thomas C. Ferguson power plant in Llano County, Texas. With this construction permit, LCRA will replace the existing 37 year-old 440 MW steam boiler with two new natural gas-fired combined-cycle combustion turbine units with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

Emission Unit Id. No.	Description
U1-STK and U2-STK	2 Natural Gas-Fired General Electric 7FA Combustion Turbines. Each unit is rated at a maximum base-load electric output of approximately 195 MW each and vented to a dedicated Heat Recovery Steam Generator (HRSG) that is equipped with a Selective Catalytic Reduction (SCR) and an Oxidation Catalyst (OC).
NG-FUG	Fugitive Natural Gas emissions from piping components
EMGEN1-STK	1340 – horsepower (hp) Diesel Fired Emergency Generator rated at 93.8 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
FWP1-STK	617 – horsepower (hp) Diesel Fired Fire Water Pump rated at 43.2 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
SF6-FUG	SF ₆ Insulated Electrical Equipment (i.e., circuit breakers) consisting of two new 24 lb SF ₆ insulated circuit breakers, six new 58 lb SF ₆ circuit breakers and 4 existing 58 lb SF ₆ insulated circuit breakers.

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or
2. is discontinued for a period of 18 months or more; or
3. is not completed within a reasonable time; and,
4. EPA may extend the 18 month period upon a satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;
2. actual date of initial startup, as defined in 40 CFR §60.2, postmarked within 15 days of such date;
3. date upon which initial performance tests will commence, in accordance with the provisions of Section V, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition V.B; and
4. date upon which certification tests of the CO₂ continuous emission monitoring system (CEMS) will commence in accordance with 40 CFR § 75.61(a)(1)(i) and 40 CFR Part 60, Appendix B, Performance Specification 3. Additionally, the initial certification or recertification application shall be submitted for the CO₂ CEMS as required by 40 CFR 75.63.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are

being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. Permittee shall notify EPA by mail within two working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in CO₂ emissions above the allowable emission limits stated in Section II of this permit.
2. In addition, Permittee shall notify EPA in writing within 15 days of any such failure described under Section III. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II, and the methods utilized to mitigate emissions and restore normal operations.
3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;
2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;
3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,
4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a

copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct and operate this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD Permit No. PSDTX1244, as finalized, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH ₄	Methane
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent
DCS	Distributed Control System
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
ERCOT	Electric Reliability Council of Texas
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
HHV	High Heating Value
hp	Horsepower
hr	Hour
HRSG	Heat Recovery Steam Generator
kwh	Kilowatt-hour
lb	Pound
LCRA	Lower Colorado River Authority
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hr
N ₂ O	Nitrous Oxides
NSPS	New Source Performance Standards
OC	Oxidation Catalyst
PSD	Prevention of Significant Deterioration

QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
SCFH	Standard Cubic Feet Per Hour
SCR	Selective Catalytic Reduction
SF ₆	Sulfur Hexafluoride
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons Per Year
USC	United States Code

II. SPECIAL PERMIT CONDITIONS

A. Facility Emission Limits

Short term emissions, in pounds per hour (lb/hr) on a 30-day basis, annual emissions, in tons per year (TPY) on a 365-day rolling average basis shall not exceed the following:

Table 1. Facility Emission Limits

ID No.	Description	GHG Mass Basis			CO ₂ e		
			lb/hr ¹	TPY ^{2,3}		lb/hr ¹	TPY CO ₂ e ^{2,3}
U1-STK	Unit 1 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO ₂		908,957.6	CO ₂		908,957.6
		CH ₄		16.8	CH ₄		353.3
		N ₂ O		1.7	N ₂ O		521.6
U2-STK	Unit 2 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO ₂		908,957.6	CO ₂		908,957.6
		CH ₄		16.8	CH ₄		353.3
		N ₂ O		1.7	N ₂ O		521.6
NG-FUG	Fugitive Natural Gas emissions from piping components	CH ₄ ⁴		16.2			327.2
EMGE N1-STK	1,340-hp Diesel Fired Emergency Generator	CO ₂ ^{5,6}	15,263.2 ¹	763.2		15,314.0 ¹	765.7
FWP1-STK	617-hp Diesel Fired Fire Water Pump	CO ₂ ^{5,6}	7,027.8 ¹	351.4		7,052.0 ¹	352.6
SF6-FUG	SF ₆ Insulated Electrical Equipment	SF ₆		0.006			131.0
Totals		CO ₂		1,819,029.8	CO ₂ e		1,821,241.5
		CH ₄		49.8			
		N ₂ O		3.4			
		SF ₆		0.006			

1. Compliance with the short term emission limits (pounds per hour) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions

- only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH₄), the remaining pollutant emission (CO₂) is not presented in the table.
 5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO₂), the remaining pollutant emissions (CH₄ and N₂O) are not presented in the table.
 6. Hours of operation for emission units EMGEN1-STK and FWP1-STK shall not exceed 100 hours of non-emergency only operation per year.

B. Requirements for Combustion Turbine

1. Combustion Turbine Generator (CTG) BACT Emission Limits

- a. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the two Combustion Turbine Units (U1-STK and U2-STK) and steam turbine generator into the atmosphere in excess of 0.459 ton CO₂/MWh(net) on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured net hourly energy output (MWh (net)) and the tons of CO₂ calculated from the equations provided in 40 CFR Appendix G or the CO₂ emissions CEMS data. The calculated hourly rate is averaged daily.
- b. Permittee shall not exceed an average net heat rate of 7720 Btu/kwh (HHV) on a 365-day rolling average from the Combustion Turbine Units (U1-STK and U2-STK) and steam turbine generator. To determine this limit, Permittee shall calculate the average net heat rate on a hourly basis consistent with equation F-20 and procedure provided in 40 CFR Part 75, Appendix F, § 5.5.2 and the measured net hourly energy output (kwh). The calculated hourly heat rate is averaged daily.
- c. Permittee shall determine the hourly stack gas volumetric flow rate from 40 CFR Part 75, Appendix G, using F_c factors updated monthly from fuel analysis or, as an alternative, permittee may install and operate a volumetric stack gas flow monitor and associated data acquisition and handling system in accordance with the CO₂ CEMS system provided in 40 CFR § 75.10(a)(3) and (a)(5).

2. CO₂ Emission Monitor or CO₂ Continuous Emissions Monitoring System (CEMS) for U1-STK and U2-STK

- a. Permittee shall install, calibrate, and operate a CO₂ emission monitor for each emission unit, U1-STK and U2-STK, and shall meet the applicable requirements, including certification testing, of 40 CFR Parts 60 and 75 to be used in conjunction with the F_c factor based on the procedures to calculate the volumetric stack gas flow rate in 40 CFR Part 75, Appendix F.
- b. As an alternative to Special Condition II.B.2.a., permittee may install a CO₂ CEMS

and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO₂ emissions discharged to the atmosphere.

- c. In accordance with 40 CFR § 75.4(b), permittee shall ensure that all required CO₂ monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR § 72.2).
- d. Permittee shall ensure compliance with the specifications and test procedures for CO₂ emission monitoring system at stationary sources, 40 CFR Part 75.
- e. Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO₂ emission monitoring system.

3. Combustion Turbine Work Practice and Operational Requirements

- a. Permittee shall calculate the amount of CO₂ emitted from combustion in tons/hr, averaged daily and converted to tpy based on equation G-4 of 40 CFR Part 75 and the average net heat rate on an hourly basis based on the heat input calculation procedures contained in 40 CFR Part 75, Appendix F, equation F-20.
- b. The calculated CO₂ emissions from Special Condition II.B.3.a. shall be compared to the measured CO₂ emissions from the CO₂ emission monitor, required in Special Condition II.B.2.a, and the calculated hourly stack gas volumetric flow rate, required in Special Condition II.B.1.c., on a daily basis. If the mean difference between the calculated and measured CO₂ emission monitor result is greater than 10% of measured CO₂ concentration, permittee shall review the emission units and monitoring instrumentation operational performance. From this review, any corrective measures taken are to be identified and recorded, and the recorded information shall include the reason for the CO₂ emissions difference and corrective measures completed within 48 hours of the corrective measures being taken. If the permittee, chooses to install and operate a CO₂ CEMS equipped with a volumetric stack gas monitoring system, then the CO₂ emission calculation from Special Condition II.B.3a and mean difference comparison is no longer a requirement and the permittee shall rely on the data from the CO₂ CEMS for compliance purposes.
- c. Permittee shall calculate the CH₄ and N₂O emissions on a 365-day rolling average. Permittee shall determine compliance with the CH₄ and N₂O emissions limits contained in this section using the default CH₄ and N₂O emission factors contained in Table C-2 of 40 CFR Part 98 and the measured actual hourly heat input (HHV).

- d. Permittee shall calculate the CO₂e emissions on a 365-day rolling average, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.
- e. Fuel for the Combustion Turbines shall be limited to natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The gross calorific value of the fuel shall be determined monthly by the procedures contained in 40 CFR Part 75, Appendix F, 5.5.2 and records shall be maintained of the monthly fuel gross calorific value for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel-fired in the Combustion Turbines or shall allow a sample to be taken by EPA for analysis.
- f. The flow rate of the fuel combusted in emission units U1-STK and U2-STK shall be measured and recorded using an operational non-resettable elapsed flow meter.
- g. Permittee shall measure and record the new energy output (MWh (net)) on an hourly basis.
- h. On or before the date of initial performance test required by 40 CFR 60.8, and thereafter, Permittee shall install, and continuously operate, and maintain the HRSG equipped with a SCR and Oxidation Catalyst so emissions are at or below the emissions limits specified in this permit and TCEQ permit No. PSDTX1244.
- i. The existing Unit Number 1 natural gas-fired utility boiler (EPN Stack 1) shall be dismantled and permanently shutdown. To document the creditable reduction for the permanent shutdown of the boiler, permittee shall notify EPA by letter of the dismantling activities within 15 days of the permanent shutdown of the existing 440 MW boiler.
- j. On or after initial performance testing, permittee shall use the combustion turbine, Heat Recovery Steam Generator, Steam Turbine and Plant-wide energy efficiency processes, work practices and designs as represented in the permit application.

4. Requirements during Combustion Turbine (U1-STK and U2-STK) Startup and Shutdown

- a. Permittee shall minimize emissions during start-up and shutdown activities by operating and maintaining the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.
- b. Emissions during startup and shutdown activities shall be minimized by limiting the

duration of operation in startup and shutdown mode as follows:

- i. A startup of each CTG (U1-STK and U2-STK) is defined as the period that begins when there is measureable fuel flow to the CTG and ends when the CTG load reaches 50 percent. A startup for each CTG is limited to six hours.
 - ii. A shutdown of each CTG (U1-STK and U2-STK) is defined as the period that begins when the CTG load falls below 50 percent and ends when there is no longer measureable fuel flow to the CTG. A shutdown for each CTG is limited to two hours.
- c. During startup and shutdown, emissions from each unit and associated equipment shall not exceed the following:

Table 2. Startup and Shutdown Emissions

ID No.	Description	Pollutant	Startup and Shutdown GHG Mass Basis ¹	Startup and Shutdown CO _{2e}
			lb/hr	lb/hr
U1-STK	Unit 1 of 2 Natural Gas Fired Combustion Turbine	CO ₂	153,392.10	153,392.10
		CH ₄	2.84	353.30
		N ₂ O	0.28	521.60
U2-STK	Unit 2 of 2 Natural Gas Fired Combustion Turbine	CO ₂	153,392.10	153,392.10
		CH ₄	2.84	353.30
		N ₂ O	0.28	521.60

¹ Startup and Shutdown lb/hr emissions are an estimate and are enforceable through compliance with the applicable special condition(s) such as Special Condition II.B.4.e and other permit application representations, such as fuel gas preheating and boiler feed pump fluid drives.

- d. Permittee must record the time, date, fuel heat input (HHV) in mmBtu/hr and duration of each startup and shutdown event. The records must include hourly CO₂ emission levels as measured by the CO₂ emission monitor (or CO₂ CEMS with volumetric stack gas flowrate) and the calculations based on the actual heat input for the CO₂, CO_{2e}, N₂O, and CH₄ emissions during each startup and shutdown event based on the equations represented in the permit application and Special Conditions II.B.4. These records must be kept for five years following the date of such event.
- e. During startup and trip conditions, Permittee shall utilize the steam turbine bypass system to direct the steam being generated in the HRSG to the condenser as needed to complete all startup operations within 6 hours.
- f. During startup and shutdown, the CTG and HRSG emissions shall comply with

all provisions of BACT emission limitations in Special Condition II.B.1 and Special Conditions II.B.4, including the emissions in the Table 2 above. The SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 50% of the plant net output.

C. Requirements for Auxiliary Combustion Equipment

1. Auxiliary Combustion Equipment Emission Limits

At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from each unit into the atmosphere, in excess of the following:

Table 3. Auxiliary Combustion Equipment Emission Limits

ID No.	Description	GHG Pollutants Mass Basis ¹		
			lbs/hr	TPY
FWP1-STK	617- hp (not to exceed) Diesel Fired Fire Water Pump	GHG mass basis	7,027.80	351.40
EMGEN 1-STK	1,340- hp (not to exceed) Diesel Fired Emergency Generator	GHG mass basis	15,263.20	763.10

¹ Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO₂), the remaining pollutant emissions are not presented in the table.

2. Auxiliary Combustion Equipment Work Practice and Operational Requirements

- a. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) are authorized to fire diesel fuel containing no more than 0.5 percent sulfur by weight. Upon request, Permittee shall provide a sample and/or an analysis of the fuel-fired in the emission units (FWP-STK and EMGEN1-STK) or shall allow a sample to be taken by EPA for analysis to demonstrate the percent sulfur of the fuel.
- b. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) are limited to 100 hours of non-emergency operation per year for each unit and a heat input value of 43.2 MMBtu/hr and 93.8 MMBtu/hr for the Diesel Fired Fire Water Pump and the Diesel Fired Emergency Generator, respectively.

- c. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) shall meet the monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
- d. Permittee shall install and maintain an operational non-resettable elapsed time meter for the Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK).
- e. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK), including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator and fire pump equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition II.C.2.a, fuel heat input values required in Special Condition II.C.2.b, hours of operation; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

D. Fugitive Emission Sources

1. Fugitive Emission Sources Emission Limits

At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from each unit into the atmosphere, in excess of the following:

Table 4. Fugitive Emission Sources Emission Limits

ID No.	Description	GHG Pollutants Mass Basis	
		Pollutant	TPY
NG-FUG	Fugitive Natural Gas emissions from piping components	CH ₄ ¹	16.20
SF6-FUG	SF ₆ Insulated Electrical Equipment	SF ₆	0.006

¹ Because the emissions from this unit are calculated to be 96% methane (CH₄), the remaining pollutant emissions are not presented in the table.

2. Fugitive Emission Sources Work Practice and Operational Requirements

- a. For emission unit NG-FUG, CH₄ emissions shall be calculated annually (calendar year). Permittee shall not exceed 520 gas/vapor valves, 1460 gas/vapor flanges and 3 gas/vapor compressors. Emissions shall be calculated annually based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems.
- b. For emission unit SF₆-FUG, SF₆ emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. Permittee shall not exceed 2 new 24 lb and 6 new 58 lb enclosed-pressure SF₆ circuit breakers with leak detection and 4 existing 58 lb SF₆ insulated circuit breakers.
- c. Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR 98.304.

III. Recordkeeping Requirements

- A. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; all records relating to performance tests and monitoring of auxiliary combustion equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with conditions II.C.2.a and II.C.2.b; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
- B. Permittee shall maintain records that include the following: the occurrence and duration of any startup, shutdown, or malfunction, performance testing, calibrations, checks, GHG emission units and CO₂ emission CEMS maintenance, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements.
- C. Permittee shall maintain records for 5 years from the event that includes the duration of startup, shutdown, the initial shakedown period for the emission units, pollution control units and CEMS, malfunctions, performance testing, calibrations, checks, maintenance and duration of an inoperative monitoring device and emission units with the required

corresponding emission data.

- D. Permittee shall maintain records of all GHG emission units and CO₂ emission CEMS certification tests and monitoring and compliance information required by this permit.
- E. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:
 - 1. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
 - 2. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
 - 3. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted;
 - 4. Any failure to conduct any required source testing, monitoring, or other compliance activities; and
 - 5. Any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator or fire pump.
- F. Excess emissions shall be defined as any period in which the facility emission exceeds a maximum emission limit set forth in this permit.
- G. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.
- H. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

IV. Shakedown Periods

The combustion turbine emission limits and requirements in conditions II.A and II.B shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed the time period for performance testing as specified in 40 CFR § 60.8. The requirements of special condition I.C. of this permit shall apply at all times.

V. Performance Testing Requirements:

- A. The holder of this permit shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units U1-STK and U2-STK and to determine the initial compliance with the CO₂ emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO₂ for the CTGs.
- B. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.
- C. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.
- D. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of CO₂ emissions being emitted into the atmosphere from emission units U1-STK and U2-STK and to determine the initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with EPA Methods 1-4 and 3b for the concentration of CO₂ for the CTGs.
- E. Fuel sampling for emission units U1-STK and U2-STK shall be conducted in accordance with 40 CFR Part 75 and Part 98.
- F. Each turbine shall be tested at or above 90% of maximum load operations, below 90% of maximum load operations but above 60% and below 60% but above 45% load operations. Each tested turbine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

- G. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.
- H. The owner or operator must provide the EPA at least 30 days' prior notice of any performance test, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the facility must provide at least 7 days prior notice of the rescheduled date of the performance test.
- I. The owner or operator shall provide, or cause to be provided, performance testing facilities as follows:
 - 1. Sampling ports adequate for test methods applicable to this facility,
 - 2. Safe sampling platform(s),
 - 3. Safe access to sampling platform(s), and
 - 4. Utilities for sampling and testing equipment.
- J. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

VI. Agency Notifications

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multimedia Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX 75202
Email: GroupR6AirPermits@EPA.gov

Permittee shall submit a copy of all compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX 75202



Texas Commission on Environmental Quality Air Quality Permit

A Permit Is Hereby Issued To
Lower Colorado River Authority
Authorizing the Construction and Operation of
Thomas C. Ferguson Power Plant
Located at Horseshoe Bay, Llano County, Texas
Latitude 30° 33' 27" Longitude -98° 22' 23"

Permits: 93938 and PSDTX1244

Revision Date: May 27, 2016

Expiration Date: September 1, 2021

A handwritten signature in black ink, appearing to read "R. D. A. Hyle".

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code (TAC) Section 116.116 (30 TAC § 116.116)]¹
2. **Voiding of Permit.** A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1) the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of \$5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC § 116.120]
3. **Construction Progress.** Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC § 116.115(b)(2)(A)]
4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC § 116.115(b)(2)(B)]
5. **Sampling Requirements.** If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling

facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC § 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC § 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction in a timely manner; comply with any additional recordkeeping requirements specified in special conditions in the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC § 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled “Emission Sources--Maximum Allowable Emission Rates.” [30 TAC § 116.115(b)(2)(F)]¹
9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification in accordance with 30 TAC §101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC§ 116.115(b)(2)(G)]
10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC § 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC § 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC § 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to “air pollution” as defined in Texas Health and Safety Code (THSC) §382.003(3) or violate THSC § 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.¹

¹ Please be advised that the requirements of this provision of the general conditions may not be applicable to greenhouse gas emissions.

Special Conditions

Permit Numbers 93938 and PSDTX1244

1. This permit authorizes emissions only from those emission points listed in the attached table entitled “Emission Sources - Maximum Allowable Emission Rates” (MAERT), and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit. Also, this permit authorizes the emissions from the planned maintenance, startup, and shutdown (MSS) activities listed in Attachment A, Attachment B, or the MAERT attached to this permit. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. Attachment B identifies the planned maintenance activities that are non-ILE planned maintenance activities that this permit authorizes to be performed.

Federal Applicability

2. These facilities shall comply with the applicable requirements of Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):
 - A. Subpart A: General Provisions.
 - B. Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
 - C. Subpart KKKK: Standards of Performance for Stationary Combustion Turbines.
3. These facilities shall comply with the applicable requirements of 40 CFR Part 63:
 - A. Subpart A: General Provisions.
 - B. Subpart ZZZZ: National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Emission Standards and Operating Specifications

4. This permit authorizes two General Electric 7FA (GE 7FA) natural gas fired combustion turbine generators (CTGs), Emission Point Nos. [EPNs] U1-STK and U2-STK, each rated at a maximum base-load electric output of approximately 195 megawatts (MW) and operating in combined cycle with its heat recovery steam generator (HRSG).
5. Emission Rates.
 - A. The concentration of nitrogen oxides (NO_x) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 2 parts per million by volume dry (ppmvd) corrected to 15 percent oxygen (O₂), on a rolling 24-hour average, subject to the following specifications: **(10/15)**
 - (1) A valid hour consists of a minimum of 4, and normally 60, approximately equally-spaced data points.

- (2) Excess emissions during initial or other major dry low NO_x burner tuning sessions are excluded. Major tuning sessions are scheduled events, and would occur after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.
- B. The concentration of carbon monoxide (CO) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 4 ppmvd corrected to 15 percent O₂, on a rolling three-hour average, for load operations at 60 percent or above.
- C. The concentration of CO from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 6 ppmvd corrected to 15 percent O₂, on a rolling three-hour average, for load operations below 60 percent.
- D. The concentration of volatile organic compounds (VOC) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 2 ppmvd corrected to 15 percent O₂, on a three-hour average.
- E. The concentration of ammonia (NH₃) from each CTG (EPNs: U1-STK and U2-STK) shall not exceed 7 ppmvd corrected to 15 percent O₂, on a rolling 24-hour average.

The concentrations above do not apply during periods of turbine MSS activities.

- 6. Also authorized under this permit are an Emergency Generator (EPN EMGEN1-STK) not to exceed 1340 horsepower (hp) and a Fire Water Pump (EPN FWP1-STK) not to exceed 617 hp. The Emergency Generator and Fire Water Pump are each limited to 100 hours of operation per year for non-emergency operation. **(4/14)**

7. Fuel Specifications.

- A. Fuel for the CTGs is limited to pipeline-quality natural gas containing no more than 5 grains total sulfur per 100 dry standard cubic feet on an hourly basis and 0.50 grain total sulfur per 100 dry standard cubic feet on an annual basis.
- B. The Emergency Generator (EPN EMGEN1-STK) and the Fire Water Pump (EPN E-PUMP2) are authorized to fire diesel fuel containing no more than 0.05 percent sulfur by weight.

Upon request by the Executive Director of the TCEQ or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel-fired in the CTGs, emergency generator, and fire water pump, or shall allow air pollution control agency representatives to obtain a sample for analysis.

- 8. Except during MSS activities, the opacity shall not exceed five percent averaged over a six-minute period from each stack or vent. During MSS activities, the opacity shall not exceed 15 percent. Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this

condition. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations or 15 percent during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

Aqueous Ammonia (NH₃)

9. The permit holder shall maintain prevention and protection measures for the NH₃ storage system. The NH₃ storage tank area will be marked and protected so as to protect the NH₃ storage area from accidents that could cause a rupture. The aqueous ammonia stored shall have a concentration of less than 20 percent NH₃ by weight.
10. In addition to the requirements of Special Condition No. 9, the permit holder shall maintain the piping and valves in NH₃ service as follows:
 - A. All operating practices and procedures relating to the handling and storage of NH₃ shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.
 - B. Audio, visual, and olfactory (AVO) checks for NH₃ leaks shall be made once a day.
 - C. As soon as possible, following the detection of a leak, plant personnel shall take one or more of the following actions:
 - (1) Locate and isolate the leak, if necessary.
 - (2) Commence repair or replacement of the leaking component.
 - (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Planned Maintenance, Startup, and Shutdown

11. The holder of this permit shall minimize emissions during planned MSS activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.
12. Emissions during planned startup and shutdown activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows:
 - A. A planned startup of each CTG (EPNs: U1-STK and U2-STK) is defined as the period that begins when there is measurable fuel flow to the CTG and ends when the CTG load reaches 50 percent. A planned startup for each CTG is limited to 360 minutes. At the conclusion of the startup period (the CTG load reaches 50 percent or 360 minutes, whichever comes first), the permit holder shall comply with the emission rates limitations in Special Condition No. 5 and the MAERT. **(4/14)**

- B. A planned shutdown of each CTG (EPNs: U1-STK and U2-STK) is defined as the period that begins when the Data Acquisition and Handling System (DAHS) receives a shutdown signal from the turbine controller and CTG load falls below 50 percent and ends when there is no longer measureable fuel flow to the CTG. A planned shutdown for each CTG is limited to 60 minutes. **(4/14)**
13. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit may be demonstrated as follows.
- A. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
 - B. For each pollutant emitted through a stack during non-ILE planned maintenance activities (See Attachment B), where emissions are measured using a CEMS per Special Condition No. 14A, the permit holder shall compare the pollutant's short-term (hourly) emissions during planned maintenance activities (as measured by the CEMS) to the applicable short-term planned MSS emissions limit in the MAERT for each calendar month.
 - C. For each pollutant emitted through a stack during non-ILE planned maintenance activities (See Attachment B), where emissions are not measured using a CEMS, the permit holder shall determine the total emissions of the pollutant through the stack that result from such non-ILE planned maintenance activities in accordance with Special Condition No. 14B for each calendar month.
 - D. For each pollutant that is not emitted through a stack during non-ILE planned maintenance activities (See Attachment B), the permit holder shall determine the total emissions of the pollutant from such non-ILE planned maintenance activities in accordance with Special Condition No. 14B, for each calendar month.
14. The permit holder shall determine the emissions during planned MSS activities for use in Special Condition No. 13 as follows.
- A. For each pollutant where emissions (during normal facility operations) are measured with a CEMS that has been certified to measure the pollutant's emissions over the entire range of a planned MSS activity, the permit holder shall measure the emissions of the pollutant during the planned MSS activity using the CEMS.
 - B. For each pollutant not described in Special Condition No. 14A, the permit holder shall calculate the pollutant's emissions during all occurrences of each type of planned MSS activity for each calendar month using the frequency of the planned MSS activity identified in work orders or equivalent records and the emissions of the pollutant during the planned MSS activity, as represented in the planned MSS permit application. In lieu of using the emissions of the pollutant during the planned MSS activity as represented in the planned MSS permit application to calculate such

emissions, the permit holder may determine the emissions of the pollutant during the planned MSS activity using an appropriate method, including but not limited to, any of the methods described in paragraphs 1 through 4 below, provided that the permit holder maintains appropriate records supporting such determination:

- (1) Use of emission factor(s), facility-specific parameter(s), and/or engineering knowledge of the facility's operations.
- (2) Use of emissions data measured (by a CEMS or during emissions testing) during the same type of planned MSS activity occurring at or on a similar facility, and correlation of that data with the facility's relevant operating parameters, including, but not limited to, electric load, temperature, fuel input, and fuel sulfur content.
- (3) Use of emissions testing data collected during a planned MSS activity occurring at or on the facility, and correlation of that data with the facility's relevant operating parameters, including, but not limited to, electric load, temperature, fuel input, and fuel sulfur content.
- (4) Use of parametric emissions monitoring system (PEMS) data applicable to the facility.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.
16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs U1-STK and U2-STK and to determine initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Test Methods 201A and 202 or Test Method 5, modified for the concentration of particulate matter less than 10 microns in diameter (PM₁₀); Test Method 8 or Test Methods 6 or 6C for sulfur dioxide (SO₂); Test Method 9 for opacity; Test Method 10 for the concentration of CO; and Test Method 25A, modified to exclude methane and ethane, for the concentration of VOC. In addition, Test Method 20 or equivalent methods shall be used to determine the concentrations of NO_x and O₂ for the CTGs.

Fuel sampling (for EPNs U1-STK and U2-STK) using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO₂ or the permit holder may be exempted from fuel monitoring of SO₂ as provided under 40 CFR § 60.4365(a). If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart KKKK, SO₂ limits shall be based on 100 percent conversion of the sulfur in the fuel to SO₂. Any deviations from those procedures must be approved by the Executive

Director of the TCEQ prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

- A. The TCEQ Austin Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

- (1) Date for pretest meeting.
- (2) Date sampling will occur.
- (3) Name of firm conducting sampling.
- (4) Type of sampling equipment to be used.
- (5) Method or procedure to be used in sampling.
- (6) Procedure used to determine turbine loads during and after the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions, or the TCEQ or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate or equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

- B. Air contaminants and diluents to be sampled and analyzed include (but are not limited to) NO_x, O₂, CO, VOC, SO₂, PM₁₀, and NH₃. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 or 40 CFR § 60.4365(a) may be conducted for monitoring SO₂.
- C. Each turbine shall be tested at or above 90 percent of maximum load operations. Also, each turbine shall be tested below 60 percent of maximum load operations but above 45 percent of maximum load operations. Each tested turbine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.
- D. Sampling as required by this condition shall occur within 60 days after achieving the maximum production rate at which each turbine will be operated, but no later than

180 days after initial start-up of each unit. Additional sampling may be required by TCEQ or EPA.

- E. Within 60 days after the completion of the testing and sampling required herein, two copies of the sampling reports shall be distributed as follows:

One copy to the TCEQ Austin Regional Office.

One copy to the EPA Region 6 Office, Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NO_x, CO, and diluents (O₂ or CO₂) from each Stack (EPNs U1-STK and U2-STK).
- A. Monitored NO_x and CO concentrations shall be corrected and reported in dimensional units corresponding to the emission rate and concentration limits established in this permit.
 - B. The CEMS data shall be used to demonstrate compliance with the emission limitations in Special Condition No. 5 and the MAERT.
 - C. The NO_x/diluent CEMS shall be operated according to the methods and procedures as set out in 40 CFR § 60.4345.
 - D. The CO CEMS shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Each CO monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters if four successive quarterly CGA have been conducted for that four-quarter period. An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur at least two months apart.
 - E. Reporting of monitoring data for demonstrating compliance with NSPS Subpart KKKK and this permit shall be conducted in accordance with the methods and procedures as set out in 40 CFR § 60.4380(b).
 - F. Compliance with the NO_x/diluent continuous emissions monitor requirements above can be demonstrated by meeting the requirements of 40 CFR Part 75 provided that the permit holder demonstrates compliance with applicable NSPS regulations.
 - G. The TCEQ Austin Regional Office shall be notified at least 21 days prior to any required relative accuracy test audit in order to provide them the opportunity to observe the testing.
18. The holder of this permit shall continuously monitor ammonia emissions from EPNs U1-STK and U2-STK when their respective SCR is in operation using one of the following methods. The NH₃ concentrations shall be corrected and reported in accordance with Special Condition No. 5. Monitor downtime shall not exceed 5 percent of the time that the

HRSRs were operated over the previous 12-month rolling period. Downtime consists of activities involving calibration, unanticipated power failure, unanticipated equipment malfunction, unplanned maintenance and planned maintenance.

- A. Install and operate an additional NO_x CEMS located upstream of each SCR system, which will be used in association with the NO_x CEMS located downstream of each SCR system, the NH₃ injection rate, and the following calculation procedure to estimate NH₃ slip:

$$\text{NH}_3 \text{ slip, ppmvd} = (a - (b \times c / 1,000,000)) \times (1,000,000 / b) \times d$$

where:

a = ammonia injection rate pound per hour (lb/hr)/17 pound per pound mol (lb/lb-mole);

b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb-mole);

c = change in measured NO_x concentration, ppmvd at 15 percent O₂, across catalyst; and

d = appropriate correction factor.

The correction factor shall be derived during compliance testing by comparing the measured and calculated ammonia slip. The ammonia inject rate and exhaust gas flow rate shall be recorded at least once every 15 minutes and be recorded as hourly averages. Each flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least annually, whichever is more frequent, and shall be accurate to within 2 percent of span or 5 percent of the design value.

- B. Install and operate a dual stream system of NO_x CEMS at the exit of each SCR system. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through an NH₃ converter to convert NH₃ to NO_x and then to a second NO_x CEMS. The NH₃ slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted).
- C. Install an ammonia CEMS. Each ammonia CEMS shall be audited at least once each calendar quarter and shall be designed and operated in accordance with manufacturer specifications.
19. The permit holder shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly natural gas consumption of each CTG. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75, Appendix D.

Recordkeeping Requirements

20. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:
 - A. A copy of this permit.
 - B. Permit application dated October 29, 2010, and subsequent representations submitted to the TCEQ.
 - C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 16 to demonstrate initial compliance.
 - D. Stack sampling results or other air emissions testing (other than CEMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.
21. The following information shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:
 - A. The CEMS data of NO_x, CO, and O₂ emissions from EPNs U1-STK and U2-STK to demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 5.
 - B. Raw data files of all CEMS data including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.
 - C. Records of the hours of operations and sulfur content of diesel fuel fired in the Emergency Generator and Fire Water Pump, pursuant to Special Condition Nos. 6 and 7.
 - D. Records of the sulfur content of natural gas fired in the CTGs pursuant to Special Condition No. 7.
 - E. Records of visible emissions and opacity observations pursuant to Special Condition No. 8.
 - F. Records of ammonia concentration, AVO checks, and maintenance performed to any piping and valves in NH₃ service pursuant to Special Condition Nos. 9 and 10.
 - G. Records of accidental releases, spills, or venting of NH₃ and the corrective action taken.
 - H. Records of NH₃ monitoring pursuant to Special Condition No. 18.
 - I. Records of MSS activities and validations pursuant to Special Condition Nos. 12, 13 and 14.

Reporting

22. The holder of this permit shall submit to the TCEQ Austin Regional Office and the Air Enforcement Branch of EPA in Dallas reports as described in 40 CFR § 60.7. Such reports are required for each emission unit which is required to be continuously monitored pursuant to this permit.

Date: October 12, 2015

Attachment A

Permit Numbers 93938 and PSDTX1244

Inherently Low Emitting (ILE) Planned Maintenance Activities

Planned Maintenance Activity	Emissions					
	NH ₃ /urea	VOC	NO _x	CO	PM	SO ₂
Turbine Air Intake Filter Maintenance					X	
Catalyst Handling and Maintenance ¹					X	
Turbine Washing - Unit Online ²					X	
Ammonia Equipment Maintenance ³	X					
Sludge Management ⁴		X				
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS			X	X		
Small equipment and fugitive component repair/replacement in VOC. ⁵		X				

Notes:

1. Includes, but is not limited to, replacement, cleaning, activation, and deactivation of SCR and oxidation catalysts.
2. Involves use of water only.
3. Includes, but is not limited to, (i) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters and screens in ammonia service and (ii) off-line NO_x control device maintenance (including maintenance of the aqueous ammonia systems associated with the SCR systems).
4. Includes, but is not limited to, management by vacuum truck/dewatering of materials in open pits and ponds, and sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.
5. Includes, but is not limited to, (i) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters and screens in natural gas, fuel oil, diesel oil, ammonia, lube oil, and gasoline service, and (ii) vehicle and mobile equipment maintenance that may involve small VOC emissions, such as oil changes, transmission service, and hydraulic system service.

Date: October 12, 2015

Attachment B

Permit Numbers 93938 and PSDTX1244

Non-Inherently Low Emitting (non-ILE) Planned Maintenance Activities

Planned Maintenance Activity	EPN	Emissions					
		NH ₃ / urea	VOC	NO _x	CO	PM	SO ₂
Combustion Turbine Optimization ¹	U1-STK and U2-STK	x	x	x	x	x	x
NO _x Control Device Maintenance - Unit Online	U1-STK and U2-STK	x		x			
Gaseous Fuel Venting	GASVENT		x				

Note:

1. Includes, but is not limited to, (i) leak and operability checks (e.g., turbine over-speed tests, troubleshooting), (ii) balancing, and (iii) tuning activities that occur during seasonal tuning or after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.

Date: October 12, 2015

Emission Sources - Maximum Allowable Emission Rates

Permit Number 93938 and PSDTX1244

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
U1-STK	GE 7FA (~ 195 MW)	NO _x (6)	18.80	73.50
		NO _x (MSS) (6)	160.00	--
		CO (6)	16.82	176.30
		CO (MSS) (6)	1800.00	--
		VOC	4.82	33.91
		VOC (MSS)	69.98	--
		SO ₂	27.07	10.87
		PM	33.43	73.10
		PM ₁₀	33.43	73.10
		PM _{2.5}	33.43	73.10
		H ₂ SO ₄	13.68	5.49
		NH ₃	17.89	71.84
U2-STK	GE 7FA (~ 195 MW)	NO _x (6)	18.80	73.50
		NO _x (MSS) (6)	160.00	--
		CO (6)	16.82	176.30
		CO (MSS) (6)	1800.00	--
		VOC	4.82	33.91
		VOC (MSS)	69.98	--
		SO ₂	27.07	10.87
		PM	33.43	73.10
		PM ₁₀	33.43	73.10
		PM _{2.5}	33.43	73.10
		H ₂ SO ₄	13.68	5.49

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NH ₃	17.89	71.84
CT1LOV-VNT	Combustion Turbine 1 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM ₁₀	0.09	0.40
		PM _{2.5}	0.09	0.40
CT2LOV-VNT	Combustion Turbine 2 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM ₁₀	0.09	0.40
		PM _{2.5}	0.09	0.40
ST1LOV-VNT	Steam Turbine 1 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM ₁₀	0.09	0.40
		PM _{2.5}	0.09	0.40
CT1GSOV-VNT	Combustion Turbine 1 Generator Seal Oil Vent	VOC	0.09	0.40
CT2GSOV-VNT	Combustion Turbine 2 Generator Seal Oil Vent	VOC	0.09	0.40
ST1SOV-VNT	Steam Turbine Generator 1 Seal Oil Vent	VOC	0.09	0.40
DSL-TK1	Diesel Tank 1	VOC	0.07	<0.01
DSL-TK2	Diesel Tank 2	VOC	0.02	<0.01
NG-FUG	Natural Gas Fugitives (5)	VOC	0.03	0.12
NH ₃ -FUG	Ammonia Fugitives (5)	NH ₃	0.12	0.51
EMGEN1-STK	Emergency Generator	NO _x	16.52	0.83
		CO	9.65	0.48
		VOC	0.89	0.04

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	0.55	0.03
		PM ₁₀	0.55	0.03
		PM _{2.5}	0.55	0.03
		SO ₂	<0.01	<0.01
FWP1-STK	Fire Water Pump	NO _x	3.81	0.19
		CO	4.12	0.21
		VOC	0.27	0.01
		PM	0.20	0.01
		PM ₁₀	0.20	0.01
		PM _{2.5}	0.20	0.01
		SO ₂	<0.01	<0.01
TURB-MSS	ILE Turbine Maintenance Fugitives (5)	PM	0.09	0.02
		PM ₁₀	0.09	0.02
		PM _{2.5}	<0.01	<0.01
		NH ₃	<0.01	<0.01
GASVENT	Natural Gas Venting	VOC	9.72	0.64
MISC-MSS	Planned site-wide MSS activities (5)	VOC	0.55	0.02
		NO _x	<0.01	<0.01
		CO	<0.01	<0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.

(2) Specific point source name. For fugitive sources, use area name or fugitive source name.

(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1

NO_x - total oxides of nitrogen

SO₂ - sulfur dioxide

PM - total particulate matter, suspended in the atmosphere, including PM₁₀ and PM_{2.5}, as represented

PM₁₀ - total particulate matter equal to or less than 10 microns in diameter, including PM_{2.5}, as represented

PM_{2.5} - particulate matter equal to or less than 2.5 microns in diameter

CO - carbon monoxide

Emission Sources - Maximum Allowable Emission Rates

H₂SO₄ - sulfuric acid

NH₃ - ammonia

- (4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
- (5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
- (6) For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply.

Date: October 12, 2015

**PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
FOR GREENHOUSE GAS EMISSIONS
ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21**

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER: PSD-TX-1244-GHG

PERMITTEE: Lower Colorado River Authority (LCRA)
P.O. Box 220
Austin, TX 78767-0220

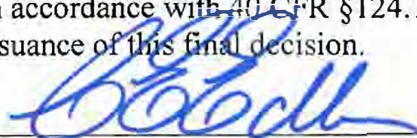
FACILITY NAME: Lower Colorado River Authority (LCRA)
Thomas C. Ferguson Power Plant

FACILITY LOCATION: 2001 Ferguson Road
Horseshoe Bay, TX 78657

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. Seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to the Lower Colorado River Authority (LCRA) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new approximately 590 megawatt (MW) natural gas-fired combined-cycle power plant to replace the existing power generation at the existing facility located in Horseshoe Bay, Texas.

LCRA is authorized to construct the LCRA, Thomas C. Ferguson power plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSDTX1244. Failure to comply with any condition or term set forth in this PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD Permit does not relieve LCRA of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR §124.15(b)(3), this PSD Permit becomes effective immediately upon issuance of this final decision.



Carl E. Edlund, Director
Multimedia Planning and Permitting Division

11/10/11

Date

LCRA, Thomas C. Ferguson Power Plant (PSD-TX-1244-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

The proposed facility is a natural gas-fired combined-cycle electric generating unit at the Thomas C. Ferguson power plant in Llano County, Texas. With this construction permit, LCRA will replace the existing 37 year-old 440 MW steam boiler with two new natural gas-fired combined-cycle combustion turbine units with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

Emission Unit Id. No.	Description
U1-STK and U2-STK	2 Natural Gas-Fired General Electric 7FA Combustion Turbines. Each unit is rated at a maximum base-load electric output of approximately 195 MW each and vented to a dedicated Heat Recovery Steam Generator (HRSG) that is equipped with a Selective Catalytic Reduction (SCR) and an Oxidation Catalyst (OC).
NG-FUG	Fugitive Natural Gas emissions from piping components
EMGEN1-STK	1340 – horsepower (hp) Diesel Fired Emergency Generator rated at 93.8 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
FWP1-STK	617 – horsepower (hp) Diesel Fired Fire Water Pump rated at 43.2 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
SF6-FUG	SF ₆ Insulated Electrical Equipment (i.e., circuit breakers) consisting of two new 24 lb SF ₆ insulated circuit breakers, six new 58 lb SF ₆ circuit breakers and 4 existing 58 lb SF ₆ insulated circuit breakers.

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or
2. is discontinued for a period of 18 months or more; or
3. is not completed within a reasonable time; and,
4. EPA may extend the 18 month period upon a satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;
2. actual date of initial startup, as defined in 40 CFR §60.2, postmarked within 15 days of such date;
3. date upon which initial performance tests will commence, in accordance with the provisions of Section V, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition V.B; and
4. date upon which certification tests of the CO₂ continuous emission monitoring system (CEMS) will commence in accordance with 40 CFR § 75.61(a)(1)(i) and 40 CFR Part 60, Appendix B, Performance Specification 3. Additionally, the initial certification or recertification application shall be submitted for the CO₂ CEMS as required by 40 CFR 75.63.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are

being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. Permittee shall notify EPA by mail within two working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in CO₂ emissions above the allowable emission limits stated in Section II of this permit.
2. In addition, Permittee shall notify EPA in writing within 15 days of any such failure described under Section III. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II, and the methods utilized to mitigate emissions and restore normal operations.
3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;
2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;
3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,
4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a

copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct and operate this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD Permit No. PSDTX1244, as finalized, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH ₄	Methane
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent
DCS	Distributed Control System
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
ERCOT	Electric Reliability Council of Texas
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
HHV	High Heating Value
hp	Horsepower
hr	Hour
HRSG	Heat Recovery Steam Generator
kwh	Kilowatt-hour
lb	Pound
LCRA	Lower Colorado River Authority
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hr
N ₂ O	Nitrous Oxides
NSPS	New Source Performance Standards
OC	Oxidation Catalyst
PSD	Prevention of Significant Deterioration

QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
SCFH	Standard Cubic Feet Per Hour
SCR	Selective Catalytic Reduction
SF ₆	Sulfur Hexafluoride
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons Per Year
USC	United States Code

II. SPECIAL PERMIT CONDITIONS

A. Facility Emission Limits

Short term emissions, in pounds per hour (lb/hr) on a 30-day basis, annual emissions, in tons per year (TPY) on a 365-day rolling average basis shall not exceed the following:

Table 1. Facility Emission Limits

ID No.	Description	GHG Mass Basis			CO ₂ e		
			lb/hr ¹	TPY ^{2,3}		lb/hr ¹	TPY CO ₂ e ^{2,3}
U1-STK	Unit 1 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO ₂		908,957.6	CO ₂		908,957.6
		CH ₄		16.8	CH ₄		353.3
		N ₂ O		1.7	N ₂ O		521.6
U2-STK	Unit 2 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO ₂		908,957.6	CO ₂		908,957.6
		CH ₄		16.8	CH ₄		353.3
		N ₂ O		1.7	N ₂ O		521.6
NG-FUG	Fugitive Natural Gas emissions from piping components	CH ₄ ⁴		16.2			327.2
EMGE N1-STK	1,340-hp Diesel Fired Emergency Generator	CO ₂ ^{5,6}	15,263.2 ¹	763.2		15,314.0 ¹	765.7
FWP1-STK	617-hp Diesel Fired Fire Water Pump	CO ₂ ^{5,6}	7,027.8 ¹	351.4		7,052.0 ¹	352.6
SF6-FUG	SF ₆ Insulated Electrical Equipment	SF ₆		0.006			131.0
Totals		CO ₂		1,819,029.8	CO ₂ e		1,821,241.5
		CH ₄		49.8			
		N ₂ O		3.4			
		SF ₆		0.006			

1. Compliance with the short term emission limits (pounds per hour) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions

- only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH₄), the remaining pollutant emission (CO₂) is not presented in the table.
 5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO₂), the remaining pollutant emissions (CH₄ and N₂O) are not presented in the table.
 6. Hours of operation for emission units EMGEN1-STK and FWP1-STK shall not exceed 100 hours of non-emergency only operation per year.

B. Requirements for Combustion Turbine

1. Combustion Turbine Generator (CTG) BACT Emission Limits

- a. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the two Combustion Turbine Units (U1-STK and U2-STK) and steam turbine generator into the atmosphere in excess of 0.459 ton CO₂/MWh(net) on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured net hourly energy output (MWh (net)) and the tons of CO₂ calculated from the equations provided in 40 CFR Appendix G or the CO₂ emissions CEMS data. The calculated hourly rate is averaged daily.
- b. Permittee shall not exceed an average net heat rate of 7720 Btu/kwh (HHV) on a 365-day rolling average from the Combustion Turbine Units (U1-STK and U2-STK) and steam turbine generator. To determine this limit, Permittee shall calculate the average net heat rate on a hourly basis consistent with equation F-20 and procedure provided in 40 CFR Part 75, Appendix F, § 5.5.2 and the measured net hourly energy output (kwh). The calculated hourly heat rate is averaged daily.
- c. Permittee shall determine the hourly stack gas volumetric flow rate from 40 CFR Part 75, Appendix G, using F_c factors updated monthly from fuel analysis or, as an alternative, permittee may install and operate a volumetric stack gas flow monitor and associated data acquisition and handling system in accordance with the CO₂ CEMS system provided in 40 CFR § 75.10(a)(3) and (a)(5).

2. CO₂ Emission Monitor or CO₂ Continuous Emissions Monitoring System (CEMS) for U1-STK and U2-STK

- a. Permittee shall install, calibrate, and operate a CO₂ emission monitor for each emission unit, U1-STK and U2-STK, and shall meet the applicable requirements, including certification testing, of 40 CFR Parts 60 and 75 to be used in conjunction with the F_c factor based on the procedures to calculate the volumetric stack gas flow rate in 40 CFR Part 75, Appendix F.
- b. As an alternative to Special Condition II.B.2.a., permittee may install a CO₂ CEMS

and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO₂ emissions discharged to the atmosphere.

- c. In accordance with 40 CFR § 75.4(b), permittee shall ensure that all required CO₂ monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR § 72.2).
- d. Permittee shall ensure compliance with the specifications and test procedures for CO₂ emission monitoring system at stationary sources, 40 CFR Part 75.
- e. Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO₂ emission monitoring system.

3. Combustion Turbine Work Practice and Operational Requirements

- a. Permittee shall calculate the amount of CO₂ emitted from combustion in tons/hr, averaged daily and converted to tpy based on equation G-4 of 40 CFR Part 75 and the average net heat rate on an hourly basis based on the heat input calculation procedures contained in 40 CFR Part 75, Appendix F, equation F-20.
- b. The calculated CO₂ emissions from Special Condition II.B.3.a. shall be compared to the measured CO₂ emissions from the CO₂ emission monitor, required in Special Condition II.B.2.a, and the calculated hourly stack gas volumetric flow rate, required in Special Condition II.B.1.c., on a daily basis. If the mean difference between the calculated and measured CO₂ emission monitor result is greater than 10% of measured CO₂ concentration, permittee shall review the emission units and monitoring instrumentation operational performance. From this review, any corrective measures taken are to be identified and recorded, and the recorded information shall include the reason for the CO₂ emissions difference and corrective measures completed within 48 hours of the corrective measures being taken. If the permittee, chooses to install and operate a CO₂ CEMS equipped with a volumetric stack gas monitoring system, then the CO₂ emission calculation from Special Condition II.B.3a and mean difference comparison is no longer a requirement and the permittee shall rely on the data from the CO₂ CEMS for compliance purposes.
- c. Permittee shall calculate the CH₄ and N₂O emissions on a 365-day rolling average. Permittee shall determine compliance with the CH₄ and N₂O emissions limits contained in this section using the default CH₄ and N₂O emission factors contained in Table C-2 of 40 CFR Part 98 and the measured actual hourly heat input (HHV).

- d. Permittee shall calculate the CO₂e emissions on a 365-day rolling average, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.
- e. Fuel for the Combustion Turbines shall be limited to natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The gross calorific value of the fuel shall be determined monthly by the procedures contained in 40 CFR Part 75, Appendix F, 5.5.2 and records shall be maintained of the monthly fuel gross calorific value for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel-fired in the Combustion Turbines or shall allow a sample to be taken by EPA for analysis.
- f. The flow rate of the fuel combusted in emission units U1-STK and U2-STK shall be measured and recorded using an operational non-resettable elapsed flow meter.
- g. Permittee shall measure and record the new energy output (MWh (net)) on an hourly basis.
- h. On or before the date of initial performance test required by 40 CFR 60.8, and thereafter, Permittee shall install, and continuously operate, and maintain the HRSG equipped with a SCR and Oxidation Catalyst so emissions are at or below the emissions limits specified in this permit and TCEQ permit No. PSDTX1244.
- i. The existing Unit Number 1 natural gas-fired utility boiler (EPN Stack 1) shall be dismantled and permanently shutdown. To document the creditable reduction for the permanent shutdown of the boiler, permittee shall notify EPA by letter of the dismantling activities within 15 days of the permanent shutdown of the existing 440 MW boiler.
- j. On or after initial performance testing, permittee shall use the combustion turbine, Heat Recovery Steam Generator, Steam Turbine and Plant-wide energy efficiency processes, work practices and designs as represented in the permit application.

4. Requirements during Combustion Turbine (U1-STK and U2-STK) Startup and Shutdown

- a. Permittee shall minimize emissions during start-up and shutdown activities by operating and maintaining the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.
- b. Emissions during startup and shutdown activities shall be minimized by limiting the

duration of operation in startup and shutdown mode as follows:

- i. A startup of each CTG (U1-STK and U2-STK) is defined as the period that begins when there is measureable fuel flow to the CTG and ends when the CTG load reaches 50 percent. A startup for each CTG is limited to six hours.
 - ii. A shutdown of each CTG (U1-STK and U2-STK) is defined as the period that begins when the CTG load falls below 50 percent and ends when there is no longer measureable fuel flow to the CTG. A shutdown for each CTG is limited to two hours.
- c. During startup and shutdown, emissions from each unit and associated equipment shall not exceed the following:

Table 2. Startup and Shutdown Emissions

ID No.	Description	Pollutant	Startup and Shutdown GHG Mass Basis ¹	Startup and Shutdown CO _{2e}
			lb/hr	lb/hr
U1-STK	Unit 1 of 2 Natural Gas Fired Combustion Turbine	CO ₂	153,392.10	153,392.10
		CH ₄	2.84	353.30
		N ₂ O	0.28	521.60
U2-STK	Unit 2 of 2 Natural Gas Fired Combustion Turbine	CO ₂	153,392.10	153,392.10
		CH ₄	2.84	353.30
		N ₂ O	0.28	521.60

¹ Startup and Shutdown lb/hr emissions are an estimate and are enforceable through compliance with the applicable special condition(s) such as Special Condition II.B.4.e and other permit application representations, such as fuel gas preheating and boiler feed pump fluid drives.

- d. Permittee must record the time, date, fuel heat input (HHV) in mmBtu/hr and duration of each startup and shutdown event. The records must include hourly CO₂ emission levels as measured by the CO₂ emission monitor (or CO₂ CEMS with volumetric stack gas flowrate) and the calculations based on the actual heat input for the CO₂, CO_{2e}, N₂O, and CH₄ emissions during each startup and shutdown event based on the equations represented in the permit application and Special Conditions II.B.4. These records must be kept for five years following the date of such event.
- e. During startup and trip conditions, Permittee shall utilize the steam turbine bypass system to direct the steam being generated in the HRSG to the condenser as needed to complete all startup operations within 6 hours.
- f. During startup and shutdown, the CTG and HRSG emissions shall comply with

all provisions of BACT emission limitations in Special Condition II.B.1 and Special Conditions II.B.4, including the emissions in the Table 2 above. The SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 50% of the plant net output.

C. Requirements for Auxiliary Combustion Equipment

1. Auxiliary Combustion Equipment Emission Limits

At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from each unit into the atmosphere, in excess of the following:

Table 3. Auxiliary Combustion Equipment Emission Limits

ID No.	Description	GHG Pollutants Mass Basis ¹		
			lbs/hr	TPY
FWP1-STK	617- hp (not to exceed) Diesel Fired Fire Water Pump	GHG mass basis	7,027.80	351.40
EMGEN 1-STK	1,340- hp (not to exceed) Diesel Fired Emergency Generator	GHG mass basis	15,263.20	763.10

¹ Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO₂), the remaining pollutant emissions are not presented in the table.

2. Auxiliary Combustion Equipment Work Practice and Operational Requirements

- a. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) are authorized to fire diesel fuel containing no more than 0.5 percent sulfur by weight. Upon request, Permittee shall provide a sample and/or an analysis of the fuel-fired in the emission units (FWP-STK and EMGEN1-STK) or shall allow a sample to be taken by EPA for analysis to demonstrate the percent sulfur of the fuel.
- b. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) are limited to 100 hours of non-emergency operation per year for each unit and a heat input value of 43.2 MMBtu/hr and 93.8 MMBtu/hr for the Diesel Fired Fire Water Pump and the Diesel Fired Emergency Generator, respectively.

- c. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) shall meet the monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
- d. Permittee shall install and maintain an operational non-resettable elapsed time meter for the Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK).
- e. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK), including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator and fire pump equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition II.C.2.a, fuel heat input values required in Special Condition II.C.2.b, hours of operation; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

D. Fugitive Emission Sources

1. Fugitive Emission Sources Emission Limits

At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from each unit into the atmosphere, in excess of the following:

Table 4. Fugitive Emission Sources Emission Limits

ID No.	Description	GHG Pollutants Mass Basis	
		Pollutant	TPY
NG-FUG	Fugitive Natural Gas emissions from piping components	CH ₄ ¹	16.20
SF6-FUG	SF ₆ Insulated Electrical Equipment	SF ₆	0.006

¹ Because the emissions from this unit are calculated to be 96% methane (CH₄), the remaining pollutant emissions are not presented in the table.

2. Fugitive Emission Sources Work Practice and Operational Requirements

- a. For emission unit NG-FUG, CH₄ emissions shall be calculated annually (calendar year). Permittee shall not exceed 520 gas/vapor valves, 1460 gas/vapor flanges and 3 gas/vapor compressors. Emissions shall be calculated annually based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems.
- b. For emission unit SF₆-FUG, SF₆ emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. Permittee shall not exceed 2 new 24 lb and 6 new 58 lb enclosed-pressure SF₆ circuit breakers with leak detection and 4 existing 58 lb SF₆ insulated circuit breakers.
- c. Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR 98.304.

III. Recordkeeping Requirements

- A. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; all records relating to performance tests and monitoring of auxiliary combustion equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with conditions II.C.2.a and II.C.2.b; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
- B. Permittee shall maintain records that include the following: the occurrence and duration of any startup, shutdown, or malfunction, performance testing, calibrations, checks, GHG emission units and CO₂ emission CEMS maintenance, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements.
- C. Permittee shall maintain records for 5 years from the event that includes the duration of startup, shutdown, the initial shakedown period for the emission units, pollution control units and CEMS, malfunctions, performance testing, calibrations, checks, maintenance and duration of an inoperative monitoring device and emission units with the required

corresponding emission data.

- D. Permittee shall maintain records of all GHG emission units and CO₂ emission CEMS certification tests and monitoring and compliance information required by this permit.
- E. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:
 - 1. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
 - 2. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
 - 3. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted;
 - 4. Any failure to conduct any required source testing, monitoring, or other compliance activities; and
 - 5. Any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator or fire pump.
- F. Excess emissions shall be defined as any period in which the facility emission exceeds a maximum emission limit set forth in this permit.
- G. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.
- H. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

IV. Shakedown Periods

The combustion turbine emission limits and requirements in conditions II.A and II.B shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed the time period for performance testing as specified in 40 CFR § 60.8. The requirements of special condition I.C. of this permit shall apply at all times.

V. Performance Testing Requirements:

- A. The holder of this permit shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units U1-STK and U2-STK and to determine the initial compliance with the CO₂ emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO₂ for the CTGs.
- B. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.
- C. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.
- D. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of CO₂ emissions being emitted into the atmosphere from emission units U1-STK and U2-STK and to determine the initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with EPA Methods 1-4 and 3b for the concentration of CO₂ for the CTGs.
- E. Fuel sampling for emission units U1-STK and U2-STK shall be conducted in accordance with 40 CFR Part 75 and Part 98.
- F. Each turbine shall be tested at or above 90% of maximum load operations, below 90% of maximum load operations but above 60% and below 60% but above 45% load operations. Each tested turbine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

- G. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.
- H. The owner or operator must provide the EPA at least 30 days' prior notice of any performance test, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the facility must provide at least 7 days prior notice of the rescheduled date of the performance test.
- I. The owner or operator shall provide, or cause to be provided, performance testing facilities as follows:
 - 1. Sampling ports adequate for test methods applicable to this facility,
 - 2. Safe sampling platform(s),
 - 3. Safe access to sampling platform(s), and
 - 4. Utilities for sampling and testing equipment.
- J. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

VI. Agency Notifications

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multimedia Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX 75202
Email: GroupR6AirPermits@EPA.gov

Permittee shall submit a copy of all compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX 75202